File Number: EB-2013-0174

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Exhibit 2

Tab 3 of 4

Distribution System Plan

Distribution System Plan Overview

Veridian's Distribution System Plan ("DSP") outlines its immediate and longer term strategy for its electricity distribution infrastructure to meet the evolving needs of its customers and other stakeholders. The plan adheres to the Ontario Energy Board's Filing Requirements for Electricity Transmission and Distribution Applications Chapter 5, entitled Consolidated Distribution System Plan Filing Requirements ("Chapter 5") dated March 28th 2013.

Veridian's DSP includes information on its asset management and decision-making processes, as well as planned capital investments for the years 2014 to 2018 in support of its rate application and has been organized using the same section headings as in Chapter 5.

The initial *Overview* section provides information on the prospective business conditions that drive the size and mix of capital investments required to meet the company's planning objectives. It also outlines sources of cost savings expected to be achieved during the plan horizon.

Following the Overview, sections of Veridian's DSP separately document:

- The DSP Table of Contents

- Veridian's *Asset Management Process*, which is the systematic approach used to identify, plan, prioritize and optimize needed investments in electricity distribution assets; and,

- Veridian's *Capital Expenditure Plan*, which sets out and justifies historic and planned capital investments for the period of 2009 to 2018.

Veridian's DSP is aligned with the Board's expectations that the plan shows how Veridian is working towards the performance outcomes that the Board has established for distributors. The DSP supports how Veridian has been, and will continue to manage its distribution system in an efficient, reliable, safe, sustainable manner, that provides value for customers through cost-effective planning and operation.

This is the first DSP to be filed by Veridian, and as such, there are no important changes identified from a previously filed plan. Veridian is committed to making continuing progress in the enhancement and development of the plan based on results, achievements, and identified opportunities for improvements.

The Distribution System Plan Overview

This section of the Distribution System Plan (DSP) provides a high level overview of the information filed in Veridian's plan for the historical years of 2009 to 2013 and the forecast years of 2014 to 2018.

Known key elements of the DSP that drive the composition of Veridian's proposed capital investments, and their corresponding affect on its rates proposal have been identified, as have the sources of any potential cost savings expected through the execution of the plan.

The information generally used throughout the DSP is based on available information established between mid-2012 to mid-2013, and should be considered as current.

Looking forward, the outcomes of ongoing activities or future events which may impact the DSP have also been identified in as much detail as currently available.

a) Key Elements of Veridian's Distribution System Plan

It is expected that the operational and service requirements driving Veridian's capital expenditures, and found within its DSP, will generally remain consistent through the 2014 to 2018 planning window. The projected expenditures for the 2014 test year, and going forward, not only reflect the typical spending needs of a distribution electric utility serving a growing customer base with a geographically distributed, and a diverse collection of physical assets but also include the ongoing planned capital sustainment investments required to replace the aging assets found in its distribution system.

There are a number of key elements that affect Veridian's DSP for the capital investment plans for the test and future years. These are:

- Planned distribution asset sustainment programs;
- Seaton Community in north Pickering;
- Seaton Transformer Station (TS) in north Pickering;
- Growth and development; and
- Provincial, regional, and municipal infrastructure improvements (road relocations).

<u>Planned distribution asset sustainment programs (2014 +)</u>

Veridian has recognized that it needs to address the serious issue of its aging distribution asset infrastructure. Prior to the test year, Veridian has managed a reactive program of unplanned sustainment to replace the assets that fail in service or those that need to be replaced due to their poor condition, before they fail or if they pose a safety risk to the public or workers. In the test year, Veridian will be implementing an ongoing proactive program of planned sustainment to replace an identified quantity of various categories of distribution assets before they fail. The proactive program not only allows Veridian to better plan for future replacements, it avoids a future bow wave of replacements, thereby smoothing financial impacts year over year as well as mitigating reliability problems by eliminating the assets most likely to fail sooner rather than when they actually fail. Starting in the test year and ongoing through the planning window of 2018 and beyond, Veridian intends to continue to invest in replacing or refurbishing its assets in order that they continue to meet all, company and customer performance expectations.

Seaton Community (2015 – 2021)

Development in the Seaton community located in north Pickering is currently underway and is expected to be a significant driver of development and new residential load customers with municipality projected quantities of 1700 lots connected per year starting in 2015 and continuing for a number of years. Based on this new load projection, additional capacity and distribution feeder infrastructure will be required by 2018 if actual connection quantities match the projections. The new feeder infrastructure is included in the 2014 capital expenditure plan as well as in subsequent year plans, to continue from their present endpoint in Ajax and extend into the Seaton Community in Pickering. These feeders once completed will bring available capacity from the existing Whitby TS to fully utilize that TS asset as well as satisfy capacity needs until the Seaton TS described below enters service.

Seaton TS (2013 – 2018)

The additional requirement for capacity for the Seaton Community is the main driver behind the Seaton TS project targeted to be in-service for 2018. The Seaton TS project itself is projected to be a capital investment of approximately $21M in 2018. The TS project has a multi-year timeline from concept through to in-service and this project is currently in progress. Veridian is planning to complete its build or buy business case for the TS (Veridian to build and own the TS, or have the transmitter, Hydro One, build and own the TS), in 2014. This would be Veridian's first transformer station if the build option prevails as the better decision. Many other distributors, including those smaller than Veridian, currently own and operate their own TSs as their business cases have shown that distributor ownership is the better option. The environmental assessment and the land purchase for the Veridian build option for the TS have been tentatively planned for 2015 but are dependent on the results of the business case. New feeder construction projects extending into the Seaton community are included in the capital investment plan for 2014 through 2018. Existing capacity at the existing Whitby TS will be fully utilized first as described above.

Growth and Development

Growth occurs at different rates between Veridian's five operating districts. It is expected that the Ajax, Belleville and Clarington districts will continue to see fast growth as it relates to the other districts, as expansion pushes out and further develops out into the GTA. Slow to little growth is expected in the Brock and Gravenhurst districts. The Seaton community as described above is the single most significant growth area expected to develop within the planning window. 1700 lots/year are being projected to be connected starting in 2015 and continuing for a number of years based on the municipality's projections at this time. Only very preliminary internal discussion has been held regarding the proposed North Pickering Airport which is located north of Highway #407. Veridian's system planning staff has already identified a long term servicing plan for the Seaton Community and for the development lands expected on either side of Highway #407.

Road Relocations (2013 – 2015)

The Ministry of Transportation's Highway #407 extension from its current end point in Pickering through to the Ajax district's eastern service boundary is currently underway with expectations to be completed between 2013 and 2015. This extension of Highway #407, located to the north of the Seaton Community, is expected to initiate similar type development of employment lands on either side in north Pickering as it has on the completed sections of Highway #407 in Mississauga. There is significant linkage between the extension of Highway #407, the Seaton Community, area growth and development, and the Seaton TS as the first three will not only be drivers for each other, but drive the necessity for the fourth. The Highway #407 extension involves significant asset removal, asset relocations, and new asset construction entirely with multiple millions in gross capital investments as well as a significant commitment of resources for this non-discretionary project, of which there are 13 sub-projects.

The Region of Durham's Highway #2 Bus Rapid Transit (BRT) projects are encompassed under a regional transit priority initiative. It involves the widening of Highway #2 through Ajax and Pickering from 4 lanes to 6 lanes with the additional lanes being for bus transit, and potentially future light rail. The widening will affect several major intersections along its route which will require significant relocations of Veridian's existing overhead assets. The Region's target for completion is March 2016.

Build Belleville is an ongoing municipal infrastructure renewal program targeting the City of Belleville's roads and bridges, water and sewage assets. The various municipal projects included are at preliminary stages in the design process and the associated road works will require significant relocations of Veridian's existing overhead assets.

Projects associated with the above and their descriptions for the 2014 test year are found in Veridian's capital expenditure plan.

b) Sources of Cost Savings

The consideration for cost savings is inherent in Veridian's philosophy in its planning and capital plan execution. Veridian has identified the following sources as having potential costs savings.

Asset Management Plan (AMP) Development

The development of the AMP will result in targeting specific assets to be replaced based on complete asset condition data. These assets will be those which will be identified as most likely to fail. Cost savings will result over time from reduced reactive after hours trouble call response which is completed at overtime labour rates as the proactive planned asset replacement would generally occur through the day during normal working hours and at regular labour rates. As well, customer satisfaction is expected to improve as system reliability metrics improve.

Veridian's Asset Condition Assessment (ACA) completed in September 2013 will be the basis in developing the Veridian's Asset Management Plan (AMP) in 2014. Of the asset categories assessed, the substation asset groups (substation transformers, substation breakers) and wood poles had sufficient data and information to better describe the condition of these assets. The other asset groups: pole mounted transformers, overhead line switches, pad mounted transformers, vault transformers, submersible transformers, pad mounted switch gear and underground primary cable had limited asset condition information available other than age, so the ACA study results and the basis to replace these assets are mainly driven by age. Even though Veridian is currently meeting the inspection requirements as mandated by the Distribution System Code (DSC), it is recognized that additional information is required to further refine the ACA output results and therefore adjust the capital investments quantities to manageable and sustainable levels year over year both from a financial and a resource aspect. Starting in the test year and going forward, Veridian is going to progressively quantify these assessments through the planning window period. Continuing to fill in the parameter and sub-parameter condition characteristics for the asset categories will refine the results of the ACA, thereby enabling better decision-making that is fully supported by the data. As such, assets though of mature age, but which are still able to operate safely and in an acceptable manner, would continue to remain in service, extending their service life. Please refer to Exhibit 2, Tab

3, Schedule 4 for further details on Veridian's asset management process, the ACA, and the AMP. The complete ACA study is found in Exhibit 2, Tab 3, Schedule 6, Attachment 1.

<u>Replacement vs. Refurbishment Option for Assets</u>

The refurbishment option, if applicable, and based on the type of asset, is many times less costly in terms of construction and installation capital costs than the replacement option for the same asset. These cost savings will be realized if, after a thorough review of the available options regarding the asset, it is determined that refurbishment is first practicable, and then deemed to be the best option for the asset.

Veridian will be including the refurbishment option for those applicable asset categories where refurbishment is a reasonable, low risk and a financially prudent alternative. One of the most likely asset categories that would realistically include refurbishment would be underground primary cable. Other asset categories such as substation transformers and substation breakers may lend themselves to considering refurbishment as an alternative, however the critical nature of these assets when combined with an increased risk of continuing to use refurbished mature assets may be deemed as unjustified when comparing short term cost saving balanced against reliability and customer expectations of reasonable asset stewardship. Where refurbishment is an alternative, the expected cost savings would result from the reduced cost in capital spend required to refurbish these assets rather than replace these assets. For example, underground primary cable refurbishment, conditional on the cable being acceptable to refurbish, has significant cost savings over trenching and installing new cable. Though, it should be noted however, that refurbishment in the majority of cases does not allow for upgrading assets to the current design and installation standards, nor benefitting from a technical or technology improvements. For example, refurbished direct buried cable would remain direct buried rather than be installed in direct buried duct, and refurbishment is still occurring on 30 to 35 year cable while new cable that is currently purchased has evolved significantly over this period for superior performance.

Proactive Planned Sustainment Programs

The proactive planned sustainment programs will result in cost savings over time from the reduction of reactive after hours trouble call response which is completed at overtime labour rates as the proactive planned replacement would generally occur through the day during normal working hours and at regular labour rates.

In the test year and going forward, Veridian has implemented an enhanced ongoing proactive program of planned sustainment to replace an identified quantity of various distribution asset categories before they fail. Advantages to this approach would be that this program not only allows Veridian to better plan for future replacements, it avoids a future bow wave of replacements, thereby smoothing financial impacts year over year as well as mitigating reliability problems by eliminating the assets most likely to fail sooner rather than when they actually fail. Prior to the test year, and the completion of the ACA, Veridian has managed a proactive program of planned sustainment to replace the assets in the substation transformers, substation breakers, wood pole, pad mounted switchgear and underground primary cable categories. In the test year, the pole mounted, pad mounted, submersible and vault transformer, and overhead switch asset categories have been included to further take advantage of the benefits realized from its current proactive programs. Please refer to Exhibit 2, Tab 3, Schedule 6, for further details on these programs.

Capital Project Engineering/GIS Integration

An improved integration between the Engineering and the Operations Information Systems (OIS) departments will result in labour cost savings in both departments by minimizing the time and effort currently expended in multiple manipulations of engineering design drawings.

The desired outcome will allow engineering design drawings to slide seamlessly back and forth between the two departments, thereby minimizing the labour cost and time needed to re-draw and modify drawings by the OIS staff before they can be inserted into the GIS system. The Engineering staff will save labour cost and time by being able to start capital project base plans from a "cut out" section of the GIS land base, which can then be easily "pasted" back with little or no additional manipulation back into the GIS. When functional, this would be not only a reduction in internal hours spent on base plans for projects, but the reduction in hours would translate into reducing the time it takes to respond to customers, as well as reduced costs to customers. It is expected that customer satisfaction will improve as deliverables to customers improve. All noted costs savings will also apply to Veridian driven capital projects as well.

Distribution Automation (Smart Grid)

Continuing investments in the Distribution Automation (DA) will result in cost savings from the reduction in regular and overtime labour costs during planned operations, such as typical day-to-day switching, and during unplanned power restoration operations. DA equipment remotely operated from Veridian's System Control Centre (SCC) eliminates the requirement for line staff to travel to the equipment's physical location to switch or operate the equipment manually. Cost savings through a more efficient use of resources result for both the operating and capital aspects. Customer satisfaction is also expected to improve as system reliability metrics improve with reduced restoration times.

Over the next 5 years, Veridian will continue to expand the automation capabilities of its distribution system. This includes projects such as the SCADA replacement, the on-going capital program to replace electro-mechanical relays with electronic relays at substations, the installation of a communication platform that provides a low latency high-bandwidth capability for smart grid device communications, and the addition of distribution management to the base

SCADA platform. Veridian envisions that the smart grid will develop through a combination of specific device and software installations coupled with embedding a smarter approach to distribution systems in the regular system planning and specifying of distribution system components. A number of smart grid device and component pilot projects are included in its capital investments. The successful devices and components will become main stream for system planners to include in their regular designs to allow further development of a smarter grid. In the test year, Veridian is planning to add distribution management system functionality to the base SCADA platform being replaced during the 2013 bridge year and as described in this rate application. This will allow Veridian to model its distribution system dynamically in real-time and introduce self-healing networks controlled from a central location rather than distributed on the distribution system.

Mobile Computing/Data Acquisition (GIS Programming Enhancements)

Veridian is continuing to expand the use of its GIS across the organization through the continued roll-out of mobile computing and web-based products. The expected cost savings will result from a reduction of labour costs associated in moving away from the current paper-based systems and towards this mobile workforce management type of system.

The same geographic information will be available to customers in a web-based application designed to provide information on power outages and estimated restoration times. The continued expansion of the system at Veridian in the test year and beyond, following the successful completion of the pilot in 2012 is targeting to further capture the efficiencies of replacing paper-based asset data gathering capture techniques. This project is directly linked and integral in filling the data gaps identified previously in Veridian's ACA. The project includes further deployment of the devices for asset field inspections and expanding the system to include capturing information for all new distribution system equipment installations and replacements.

Standards Department - Asset Failures

All asset failures are analyzed to determine the root cause of failure. Any trending on any particular asset type, manufacturer, style, or age, etc., is recognized with appropriate actions identified. In some cases, the action will be the replacement of the same, or similar style of asset prior to any additional failures, or the identification of some sort of remedial action. Cost savings will result over time from the reduction of reactive after hours trouble call response which is completed at overtime labour rates as the proactive planned replacement would generally occur through the day during normal working hours and at regular labour rates.

Standards Department – Design Standards & Specifications

Veridian's Standards Department will continue to develop its engineering design standards and specifications in an ongoing effort to drive for cost savings by "standardizing" the design and construction of Veridian's capital projects. With Veridian's diverse service areas, significant legacy assets, and its capital expenditure plan commitments, the requirement for standardization is key to reducing the labour costs in the engineering design process, reducing the asset components required to be maintained in inventory, and completing construction in a consistent and repeatable manner. Once standardization is fully in place, the next step will be to optimize the execution and delivery of the engineering and construction tasks not only for capital projects but for operating and maintenance activities as well to further drive cost savings, process improvements, and overall efficiency.

c) Period covered by DSP

Veridian's DSP covers the historical years of 2009 to 2013 and the forecast years of 2014 to 2018.

d) Vintage of Information

The information generally used throughout the DSP are based on available information established between mid-2012 to mid-2013, and should be considered as current.

e) Changes from Previous DSP

This is the first DSP to be filed by Veridian, and as such, there are no important changes identified from a previously filed plan.

f) Other Influences on Plan Outcomes

The aspects of Veridian's DSP that are contingent on the outcome of future events are:

- the Seaton Community;
- the continuing growth and development in its service area; and
- third party driven road relocations.

As noted previously in this exhibit, the Seaton Community is a significant influence and driver in Veridian's capital investment plans. The deciding factor will be whether the projected in-service connections materialize as planned. If economic conditions slow, development will most likely slow as well resulting in a delayed need for related capital spend. The Seaton TS may be delayed beyond its current planned in-service date of 2018. However, the new feeder infrastructure cannot be delayed in the event that the projections are accurate and in-service connections are occurring as expected.

Growth and development, and their related capital spend are similarly driven by economic conditions which may result in a delayed need for related capital spend if the economy slows.

Similarly, some third party road relocations may not proceed as planned and may be deferred either short term (a year), or long term (>2 years) based on economic conditions, and other priority drivers in the third party's own capital programs. Veridian will respond to these non-discretionary projects to the best of its ability.

Veridian is included in the Regional Planning Process (RPP), which is the consultation between itself and other regional distributors, the transmitter (Hydro One), and the Ontario Power Authority (OPA) for the purpose of exchanging information related to system planning. It is the first step to completing the Regional Infrastructure Plan (RIP). No material impacts have been incorporated into Veridian's DSP based on the preliminary nature of the planning process at this time. Any impacts will need to be included in the future as necessary. Please refer to Exhibit 2, Tab 3, Schedule 2, for additional details.

Attachment 1 of 1

DSP Table of Contents

DSP Table of Contents

1

Coordinated Planning with Third Parties

This section of the Distribution System Plan (DSP) describes how Veridian has met the OEB's expectations in coordinating regional infrastructure planning. It includes the types of consultations, the parties involved, the timing of any deliverables as a result of the consultations, the impacts on Veridian's DSP, and the responses from the third parties.

a) Descriptions of Consultations

Veridian is involved in the following consultations:

Regional Planning Process (RPP)

Veridian is involved in the RPP as the first step to completing the Regional Infrastructure Plan (RIP) and has been included in five (5) different Regions and Groupings due to its diverse service area:

- GTA North – Group 1
- Metro Toronto – Group 1
- GTA East – Group 2
- Peterborough to Kingston – Group 2
- South Georgian Bay/Muskoka – Group 2.

Only one preliminary pre-planning meeting has been scheduled by the transmitter and was attended by Veridian for the GTA East Region on September 10, 2013. There are no future meetings scheduled at this time for any other Regions including the GTA East Region.

No material impacts have been incorporated into Veridian's DSP based on the preliminary nature of the planning process at this time. Any impacts will need to be included in the future as necessary.

There are no deliverables identified at this time due to the very preliminary nature of the RPP.

A letter from the Transmitter (Hydro One) dated September 18, 2013 providing the status of the RPP can be found in Exhibit 2, Tab 3, Schedule 2, Attachment 2, immediately following this exhibit. No significant progress has been noted at this time.

Veridian has been asked to respond to the transmitter with respect to Regional Infrastructure Planning Launch & Amendments to the Transmission System Code and Distribution System Code. It has been requested that information be supplied on any foreseen need for additional transmission connection capacity to support Veridian's distribution system. The response to this request is dated October 17, 2013 and was submitted on October 18, 2013. However, Veridian is aware of an anticipated need for transmission connection capacity in the area of north Pickering known as the Seaton TS project in order to service a new, large development there known as the Seaton Community. Both the Seaton TS and the Seaton Community have been described in Exhibit 2, Tab 3, Schedule 1. This need will be shared with the transmitter in a formal response to the request, as set out in the Distribution System Code (DSC).

Consultations with Organizations

In addition to the RPP initiative, Veridian actively communicates with key organizations responsible for the planning and operation of the electrical system in Ontario. This includes the OPA, Hydro One and other distributors, with details found in Table 1.

Table 1 – Veridian Involved Consultations with Organizations

Organization	Purpose of the Consultation	Distribution System Plan Impact(s)
OPA	Veridian has regular ongoing communication with the OPA concerning Renewable Energy applications, CDM programs and other OPA initiatives. Additionally, Veridian participated in an OPA initiated discussion on potential regional supply issues in July 2011. It was highlighted to the OPA at that time that Veridian saw substantial load growth expected in north Pickering related to expected residential growth in the new Seaton Community development. Load growth was expected to require a new transmission connected station. The OPA was satisfied at that time that this need was a local supply issue, with the transmitter already involved. As such, a regional plan did not need to be initiated. With the new Regional Planning initiative, Veridian expects that this may be revisited.	CDM and REG project effects included in Veridian's capital plans. Seaton TS included in the 5 year capital plan with an expected 2018 in service date.

Organization	Purpose of the Consultation	Distribution System Plan Impact(s)
Transmitter (Hydro One)	Veridian initiates twice annual (typically) planning meetings with representatives from Hydro One concerning supply plans for all Veridian districts, discussion of operational items like OGCC and Veridian System Control Centre coordination and other items of mutual interest.	Generally minor impact. Can inform the DSP by helping to coordinate efforts between Hydro One and Veridian for particular projects. This forum is usually how long term supply issues are first brought forward. Those discussions can result in project impacts to the DSP.
Other Distributors	As required frequency. May be initiated by Veridian or counterpart distributors for various reasons including mutual assistance after significant weather events, technical investigations/research, LTLT resolution, operational matters along service territory borders, project coordination on work involving other distributor's distribution system interconnections	Minor impact to DSP.

Consultations with Customer and Other Stakeholders

Details on customer consultations and engagement can be found in Exhibit 1, Tab 2, Schedule 1.

b) Regional Planning Process Deliverables

As noted above, there are no deliverables identified at this time due to the very preliminary nature of the RPP.

c) OPA Comment Letter on REG investments

The OPA's Letter of Comment dated September 6, 2013 in relation to Veridian's REG investments can be found as Exhibit 2, Tab 3, Schedule 2, Attachment 1, immediately following this exhibit.

Attachment 1 of 2

Comment Letter provided by OPA in relation to REG investments

OPA Letter of Comment:

Veridian Connections Inc.

Renewable Energy Generation Investments

September 6, 2013

ONTARIO POWER AUTHORITY

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Veridian Connections Inc. – Distribution System Plan

The OPA received a letter dated August 19, 2013 from Veridian Connections Inc. ("Veridian") with respect to its Renewable Energy Generation Investments. The OPA has reviewed the letter and has provided its comments below.

OPA FIT/microFIT Applications Received

Veridian Connections Inc. indicates in Table 1 of their letter, that as July 31, 2013, they have received 34 FIT applications totalling 32,353 kW of capacity, and 560 microFIT applications totalling 4,610.09 kW. Of these, 8 FIT applications and 130 microFIT applications have been connected to Veridian's distribution system, representing 1,550 kW and 914.78 kW of capacity, respectively. Veridian has also provided the total number of Connection Impact Assessments ("CIAs") which have been issued, for FIT projects in their service area. Veridian notes that 18 CIAs have been issued for their service territory, representing 39,008 kW of capacity, greater than the total of their FIT applications. The reason for this disparity is that Hydro One has distribution facilities which are embedded in Veridian's distribution system and it received a FIT application to connect 10,000 kW of capacity. Veridian was required to complete the CIA for this project even though the generator will connect directly to Hydro One's embedded distribution system.

Ontario Power Authority
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According to the OPA's information, to date the OPA has received and offered contracts to 30 FIT applications totalling 24,078 kW of capacity which remain active to date. Of these, 8 applications totalling 1,550 kW have come into commercial operation. The OPA is also aware of the 10 MW embedded FIT application within Veridian's service territory. The difference between total application capacity reported between the OPA and Veridian is due to differences in the capacity requested by proponents of the distributor, and the contract capacity awarded to proponents by the OPA.

Additionally, the OPA has received and offered contracts to 134 microFIT applications within the Veridian service territory, totalling 939.275 kW of capacity which remain active to date.

The OPA finds that the information contained in Table 1 of Veridian's letter is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

At this time, neither a Regional Infrastructure Plan, nor an Integrated Regional Resource Plan has been completed for Veridian's service territory. Except for one distribution system expansion to accommodate a generation facility with a capacity allocation of 25.012 MW currently scheduled for connection in 2014, Veridian has no planned renewable energy generation capital investments and indicates that its distribution system can accommodate the remaining and forecast applications without any further capital investments for 2014.

On page 3 of their submission, Veridian outlines their participation with the OPA through ongoing system planning activities. To date, the OPA has not initiated a formal regional planning process with Veridian. However, over the last three years, the OPA and Veridian have participated in discussions regarding long-term demand growth in their service territory, and the need for new supply points, among them Seaton TS. Veridian has also provided the OPA with data to assist in planning the bulk transmission system serving this area, particularly following the retirement of Pickering nuclear generating station.

Veridian notes that it is part of "Group 2" for regional planning prioritization and that it looks forward to participating with the OPA and Hydro One in the regional planning process in 2014 and 2015. The OPA also looks forward to working with Veridian in the execution of the regional planning processes, and appreciates the opportunity to comment on its Renewable Energy Generation Investments information.

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Attachment 2 of 2

Comment Letter provided by Hydro One in relation to Regional Planning

Hydro One Network Inc.
483 Bay Street
15th Floor, South Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345-5420
Fax: (416) 345-4141
ajay.garg@HydroOne.com

September 18, 2013

Mr. Craig Smith
Manager, Planning & Maintenance
Veridian Connections Inc.
55 Taunton Road East
Ajax, Ontario L1T 3V3

Via email: csmith@veridian.on.ca

Dear Mr. Smith:

Subject: Regional Planning Status

In reference to your request for a regional planning status letter, please note that your Local Distribution Company (LDC) belongs to the following Regions and Groupings:

1. GTA North – Group 1
2. Metro Toronto – Group 1
3. GTA East – Group 2
4. Peterborough to Kingston - Group 2
5. South Georgian Bay/Muskoka – Group 2

A map showing details with respect to the 21 Regions/Groups and list of LDCs in each Region is attached in Appendix A and B respectively.

I. Group 1 Regions

This letter confirms that a regional planning process for sub-regions within GTA North and Metro Toronto (Group 1) is already underway. The two planning groups are led by the Ontario Planning Authority (OPA) and include representatives from Hydro One, the Independent Electricity System Operator (IESO) and the directly affected LDCs in the two Regions. The two groups were established to assess the reliability needs of the sub area within the two Regions and to develop an integrated plan to assess the appropriate mix of investments (e.g. CDM, DG and wires) to address the electricity needs of the area. At this time, the planning process is transitioning to align with the new regional infrastructure planning process established by the OEB. Details of the process can be found in the Process Planning Working Group (PPWG) Report.[1]

It is expected that an Interim Integrated Regional Resource Plan (IRRP) to address near and medium-term needs for the two Regions will be complete in 4th quarter of 2014 and a final IRRP for the two Regions addressing longer term needs for this region will be complete in 2015.

[1] Final Planning Process Working Group (PPWG) Report to the Board.

GTA North Region

The GTA North Region does not significantly affect Veridian Connections. The associated IRRP process has so far identified the following transmission reinforcements to address the near and medium-term reliability needs of the area:

- Installation of two in-line breakers and associated motorized disconnect switches on circuit B82V/B83V at or close to the Holland TS property.
- Design and implementation of a Load Rejection (L/R) scheme for the stations connected to B82V/B83V system, or have available operational measures adequate for providing similar relief, as permitted by ORTAC.
- Improve reliability of supply from the 230kV "Parkway Belt" circuits (V71P/V75P).

The wires solutions for GTA North Region are now being further developed by Hydro One as part of the Regional Infrastructure Plan with an expected in-service date of 2017 for the first two solutions. There are a number of options for addressing the reliability of supply from the Parkway Belt. Hydro One will confirm the options, scope, cost estimates and schedule of the above facilities to optimize their specifications and configuration as part of the Regional Infrastructure Plan.

Metro Toronto Region

Regional planning for a sub-region of Metro Toronto Region is currently underway and is in the options development phase of the OPA's IRRP process. This sub-region also does not affect Veridian Connections. The remaining portion of the region will include planning and assessment of the surrounding 230kV system and is expected to be initiated in 4th quarter of 2013. Hydro One will formally notify your organization in advance, along with other stakeholders, prior to launching the regional planning process for this sub-region.

II. Group 2 Regions

This letter is to also confirm that the regional planning process has not been initiated nor has a Regional Infrastructure Plan (RIP) been developed for the three Regions in Group 2. Hydro One will formally notify your organization in advance, along with other stakeholders, prior to launching the regional planning process for any of these Regions.

The new planning process provides flexibility, during the transition period to the new process, and will ensure that both distribution and transmission planning continue to address any short-term needs. Hydro One looks forward to working with Verdian Connections Inc. in executing the new regional planning process.

If you have any further questions, please feel free to contact me.

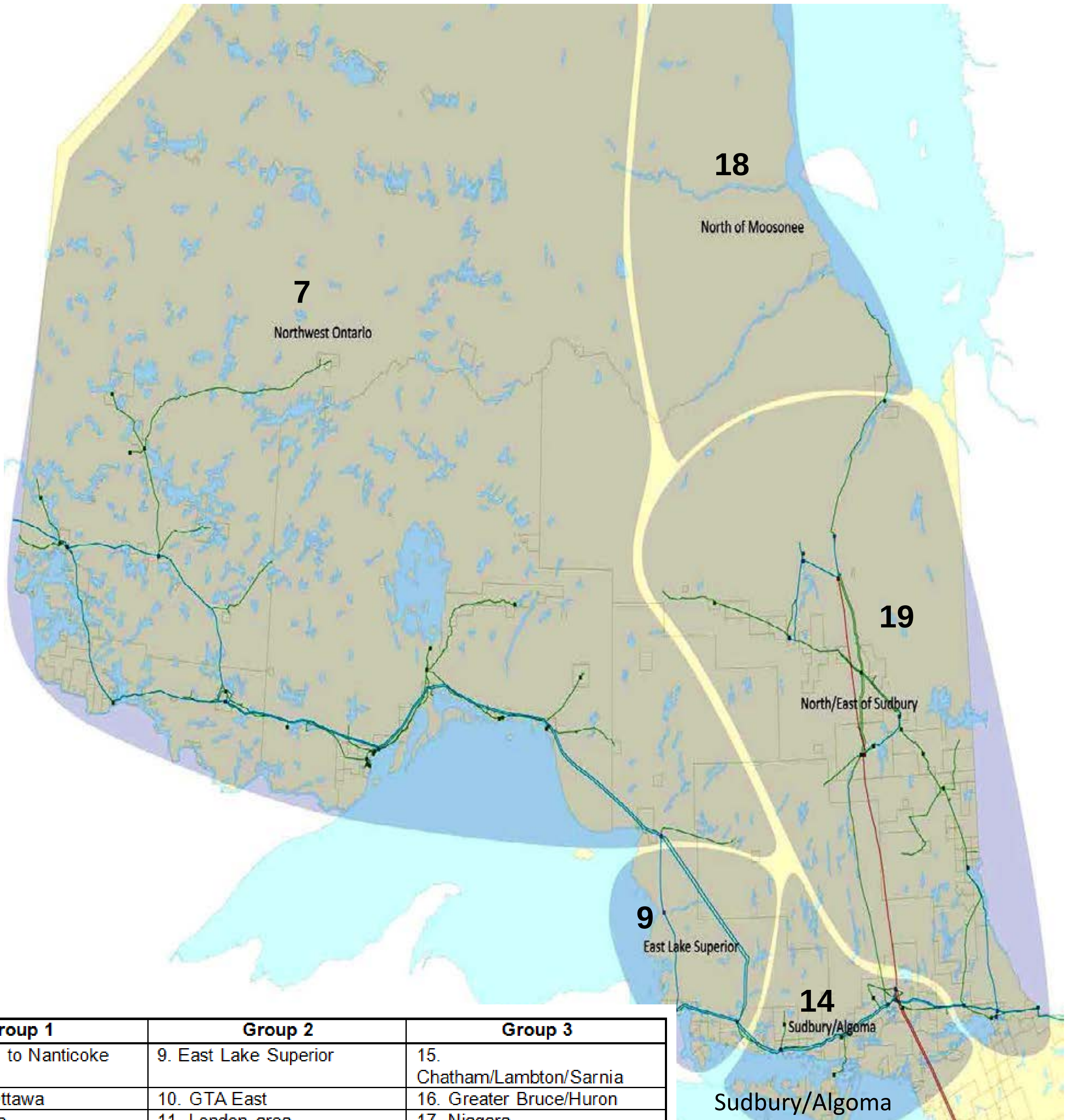
Sincerely,

Ajay Garg, |Manager - Regional Planning Coordination and Transmission Load Connections|
Hydro One Networks Inc.

Cc:
Bing Young, Director – Transmission System Development
Farooq Qureshy, Manager – Transmission Planning (Central and East)
Brad Colden, Manager – Customer Business Relations

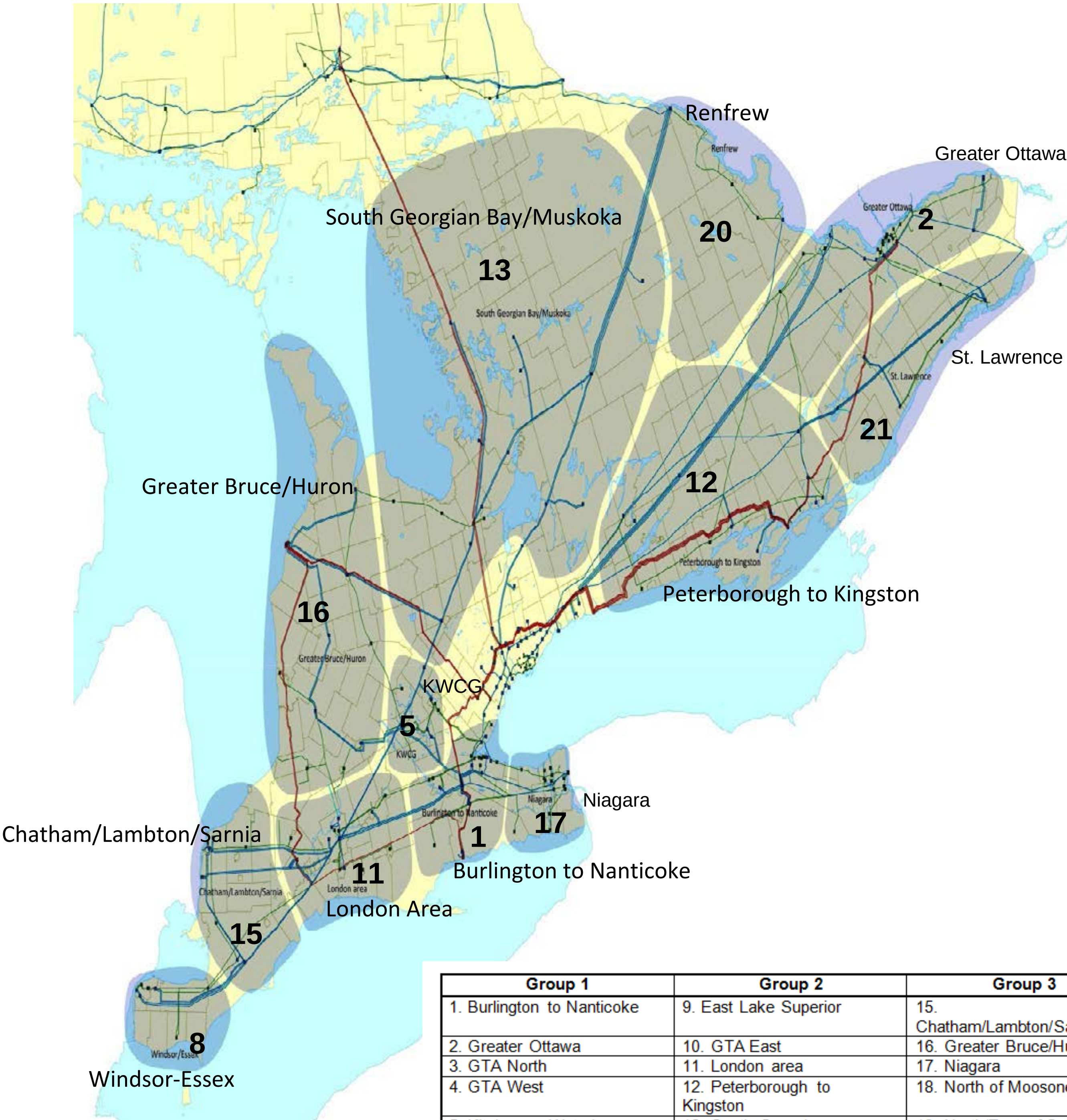
Appendix A: Map of Ontario's Planning Regions

Northern Ontario



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
3. GTA North	11. London area	17. Niagara
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Southern Ontario



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
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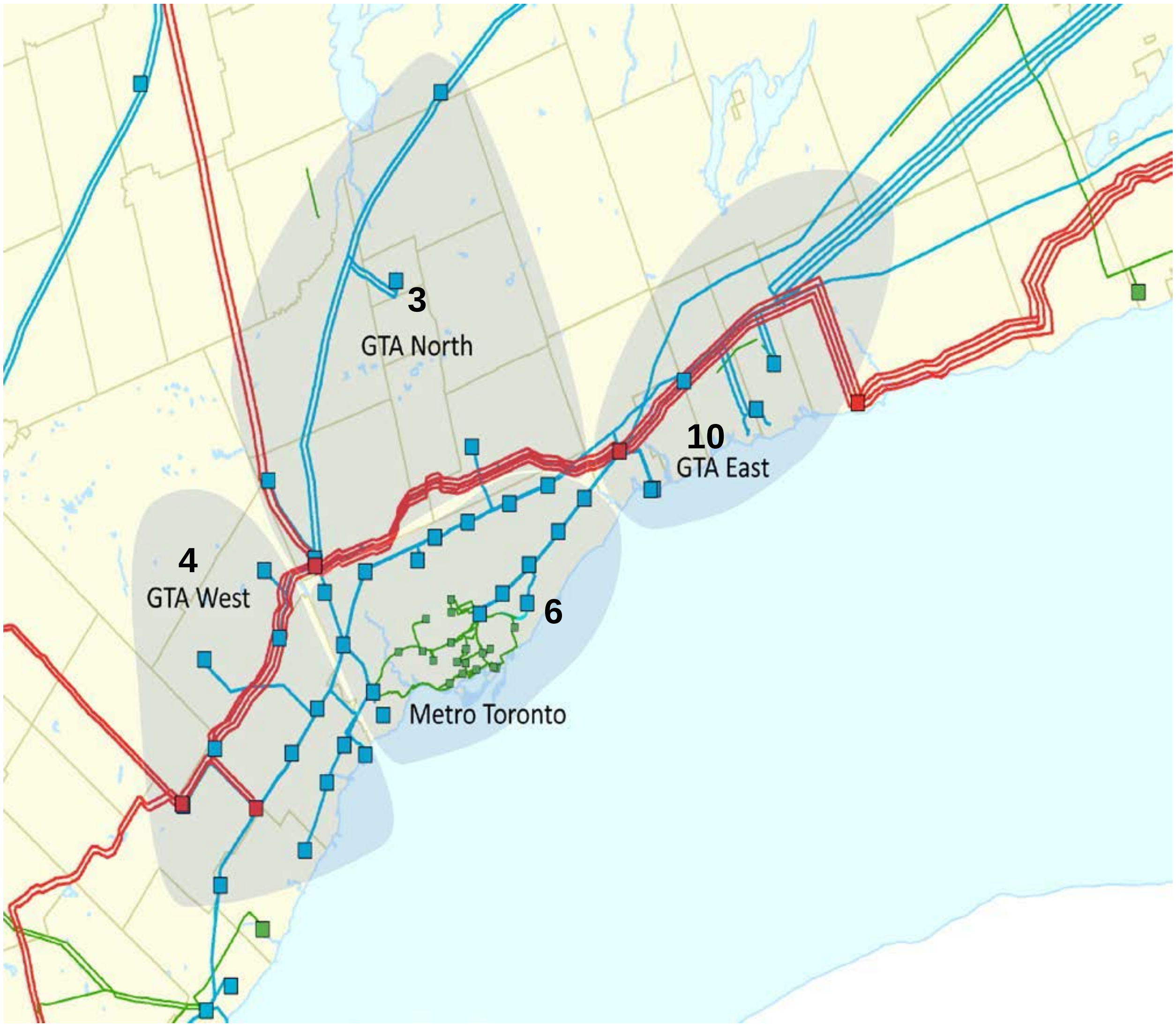
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
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4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Brant County Power Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	• Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham-Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A →This region is not within Hydro One’s territory

10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc. • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.
13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.

14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham-Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp.
18. North of Moosonee	N/A →This region is not within Hydro One's territory
19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.

20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

Performance Measurements

This section of the Distribution System Plan (DSP) describes the performance measures and metrics that Veridian uses to monitor its distribution system and planning performance.

A summary of system performance trending for the historical years of 2006 to 2012 is provided. Since this is the first plan filed by Veridian, there are no adverse deviations in performance trends identified from a previously filed plan.

The results of the system performance measures and metrics and their impact on the DSP, and how they have been used to improve the asset management and capital expenditure planning process is described as well.

a) Performance Measures

On a yearly basis, the corporate performance scorecard, along with the complementary performance measures of the OEB's Electricity Distributor's Service Quality Requirements (ESQRs), are used to measure Veridian's performance as a company. Both are reviewed on a quarterly basis to ensure continued alignment with the overall corporate business strategy and objectives, as well as regulatory targets. Results indicates the company's progress throughout the year and allows early interventions should trending be unfavourable or underperforming. Results are also used as a benchmark for improvement year over year within the company as well as an outside comparator to other distributors.

Following are the performance measures and business effectiveness and/or efficiency aspects that Veridian is currently using, not all of which are on the corporate performance scorecard or identified as ESQRs.

Reliability Performance

These performance measures address both customer oriented performance and system operations performance. The measures track system annual SAIFI, SAIDI and CAIDI values for both Veridian only distribution system caused outages, and the total values due to both Veridian's distribution system caused and loss of supply interruptions. Also calculated is the ratio of Veridian's distribution system caused outages to the total values.

Veridian places a high level of importance on ensuring distribution system reliability and capital investments meet the expectations of its customers. Veridian strives to continually improve its processes for collecting, measuring, analyzing and utilizing outage information in order to effectively manage distribution system reliability throughout its service area. The process may identify specific areas or assets that require remedial action for inclusion within the planned programs or as a specific project in the capital expenditure plan, or that additional inspection and maintenance activities are necessary within its O & M programs.

In 2010, Veridian established a formal internal reliability improvement team (Reliability Committee). On a quarterly basis, the team meets to formally analyze outage causation data and make recommendations for reliability improvement. All Veridian feeders are ranked, in terms of their quarterly performance, from worst performing to best performing. Worst performing feeders are analyzed in detail to determine outage causation and the information is utilized to inform Veridian capital and maintenance plans. The internal reliability team is comprised of senior engineering and operations staff and includes the President and CEO.

A subset of the internal reliability team monitors distribution system outages on a daily basis and, correlated with customer complaints, initiates an appropriate level response to address reliability concerns on a more immediate basis versus the quarterly review described above. An example of this is Veridian's response to a deteriorating level of reliability in the southern area of Ajax during the summer of 2012. Immediate steps were taken to perform tree trimming ahead of the regularly scheduled interval and to replace distribution system components to prevent wildlife contact. The result was an immediate and significant improvement in reliability for customers in this area of Veridian's service territory.

Veridian has a significant number of feeders that are embedded in Hydro One's distribution system. As a result, Veridian customers are subjected to the reliability of Hydro One's distribution system, including response times for Hydro One crews. These outages are recorded as Loss of Supply or Code 2 as per the OEB's reliability reporting requirements. Veridian recognizes that there is an opportunity for the improvement of reliability for its customers by working with Hydro One to solve issues related to operational control of Hydro One distribution system assets controlling electricity supply to Veridian customers. Veridian has initiated discussions with Hydro One to explore the possibility of establishing safe work practices to operate Hydro One assets affecting Veridian customers during prolonged distribution system outages.

Veridian is a member of the Canadian Electricity Association (CEA) Service Continuity Committee and utilizes its membership to discuss and understand best practices with regards to a managed approach to improving distribution system reliability and to perform peer comparisons of reliability statistics. Veridian's reliability compares well within this national group of utilities.

Planned Inspection and Maintenance Program

The performance measure in place is that all programs, activities and quantities that have been identified to be inspected and/or maintained, or replaced are in fact completed within in the year that they are scheduled.

The OEB's Distribution System Code (DSC) identifies the minimum inspection requirements for a distributor for its distribution system. To remain compliant, Veridian completes its planned program of planned inspection and maintenance yearly. This performance measure has been continually reinforced with staff to emphasize the importance of completing activities as scheduled and not allowing slides into the following year. Completion of this performance measure is not only a matter of compliance, but results from the inspection and maintenance programs allow a continual update of the asset database in Veridian's Geographic Information System (GIS), which serves as its distribution asset database. The programs mean that assets are visited regularly and their condition assessed so any necessary actions are taken as promptly as possible in a proactive approach based on what is found, in particular if any safety hazard or concern is identified. Please refer to Exhibit 2, Tab 3, Schedule 6, for details on Veridian's inspection and maintenance programs. Additionally, proactive inspection provides the opportunity to mitigate reactive unplanned outages which negatively impact reliability metrics and customer satisfaction, and increased costs for staff to respond after-hours on overtime labour rates. As with every other Ontario distributor, Veridian's inspection and maintenance programs are audited on a yearly basis as required by Ontario Regulation 22/04. Veridian has achieved compliance in this portion of the audit each year since the regulation came into effect in 2004.

Substation Loading/Capacity

The measure indicates the effectiveness of Veridian's system planning in regards to loading vs. capacity analysis, with enough reasonable capacity being available when needed for any new load being the gauge of success. Veridian's municipal substations have been identified as being the single most critical asset category within its distribution system. Therefore Veridian has planned for increased capital investment in this asset category in its capital expenditure plan for the test year and going forward.

Veridian looks to maintain its area actual load profile between the two main capacity ratings of the substation transformer as its operating limits. Substation transformer base capacity is rated as ONAN (Oil Natural Air Natural) MVA which is the capacity without forced fan cooling. The next high capacity rating for the same transformer is known as ONAF (Oil Natural Air Forced) MVA and is the increased capacity by a known percentage. This next level is the acceptable limit to operate the transformer at without overload. For example, a 10/13.3 MVA transformer would have the 10MVA as its base capacity rating, and 13.3MVA as its fan capacity rating MVA. Veridian deems this a reasonable operating philosophy in that the use of the asset is maximized but that it still operates within its equipment ratings. There is enough capacity and time buffer introduced to flag necessary actions early enough and identify substation needs to deliver just in time alternatives. The performance measure is to maintain the trend line for each identified operating area within the ONAN and ONAF ratings as described above. Please refer to Exhibit 2, Tab 3, Schedule 8, for additional details on system planning criteria.

Standards Department - Asset Failures

All asset failures are analyzed to determine the root cause of failure. Negative performance trending on any particular asset type, manufacturer, style, or condition such as age, etc., is recognized, with appropriate actions identified. In some cases, the action will be the replacement of the same or similar style of asset prior to any additional failures, the identification of some sort of remedial action, or continued monitoring and trending. Performance tracking of failing assets is ongoing and analysis results are incorporated into purchasing and inventory considerations, capital design and O&M activities on an as required basis.

Power Quality

Veridian has found that the number of power quality issues that it is made aware of that arise during a typical year are small, to the point that the numbers do not warrant their own performance measure at this time. Once investigated by Veridian, the problems are usually found to be on the customer's side of the meter. Veridian is aware that power quality issues will continue to occur, the quantity will be monitored and will be addressed accordingly. Veridian may consider establishing an appropriate performance measure should the quantity of these power quality issues increase significantly.

Planned Capital Expenditure Completion Rate

The Planned Capital Expenditure Completion Rate is a performance measure on the corporate performance scorecard. This measure is an indicator of how successful the planning and execution phases are in completing the Veridian driven planned projects in the capital expenditure plan. The measure excludes any capital projects completed for third parties such as residential subdivisions, general services, and road relocations. Capital completion is monitored and measured throughout the year and is expressed as a percentage of capital project capital spend either in service, or expected to be in service before year end for Veridian driven capital projects against the sum of the capital budgets for Veridian driven capital projects. Staff meet and review capital projects on a bi-weekly basis to assess progress, identify potential problems and make decisions on any necessary adjustments to maintain project schedules. Unexpected changes to priorities that occur, or any identified changes to capital project costs that are of a material nature, are monitored, reviewed, reported and reallocated as necessary within the capital spend envelope on a quarterly basis.

Safety

The safety component is always present in all work that Veridian undertakes and as such is considered more as an "investment in safety" rather than a "cost of safety". Safety is continually monitored and is incorporated into the individual capital projects, as well as the overall capital expenditure plan. The findings from the safety incident reporting process translate into adjustments to operating and maintenance activities and practices, as well as engineering design changes for capital projects to eliminate or mitigate safety hazards.

Safety is a key performance measure that is included on the corporate performance scorecard. There are two measures used: lost time accident frequency rate, and lost time accident severity rate. These safety measures speak for themselves and are included to represent the emphasis and importance that Veridian places on this category. Initially, engineering controls try to eliminate, or mitigate the project's safety risks, and then later effective safe work practices and personal protection eliminate or mitigate safety risks during the construction phase. Collectively in the end, there is a safe work environment for Veridian workers, its contractors, and members of the public. The only acceptable targets for both measures are zero. With safety being so prevalent and paramount in importance, effectively managing costs associated with safety, balanced with safety rules and regulation compliance is an ongoing task for which all parties; the employer, supervisors, and workers, are responsible. Continuing to remain in compliance is a significant cost driver of Veridian's operating budget for its training program.

Operations and Maintenance Costs

Operations and maintenance costs for distribution assets are reviewed regularly and the impact of capital investments targeted to reduce these costs are assessed through the annual financial planning process. O&M costs per customer targets are included within the overall OM&A cost per customer measure within Veridian's corporate performance scorecard. Veridian's DSP and overall capital planning processes impact O&M costs through the planned and unplanned costs of inspection and maintenance programs as well as through costs of reactive operations related to equipment failure. As part of overall lifecycle management, O&M costs may increase or decrease dependent upon where major assets are within their lifecycle and whether asset management is focused more highly on maintenance or on replacement. As a result, the efficacy and efficiency of programs within Veridian's DSP have a direct impact on O&M costs.

Customer Bill Impact

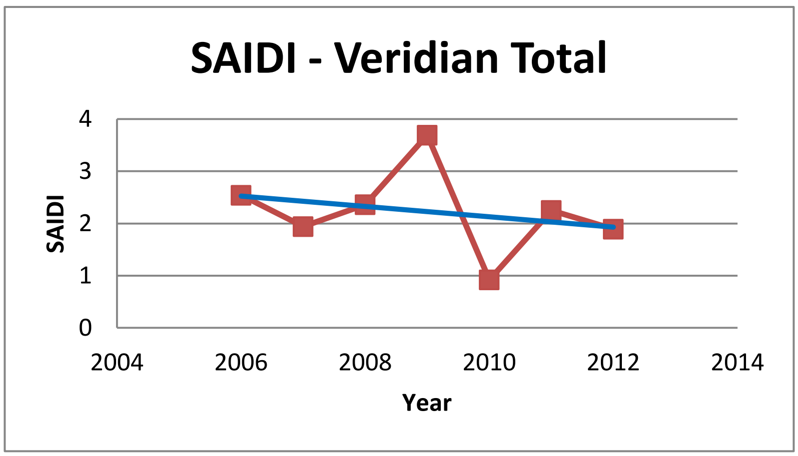
Veridian's lifecycle asset management and overall DSP consider short and long term customer bill impacts as input for maintenance versus refurbishment versus replacement decisions. Veridian is mindful of and seeks to smooth customer bill impacts in its asset management practices. While lumpy capital expenditures cannot always be avoided, a focus on smoothing investments to avoid sharp bill impacts is a key planning element.

b) Summary of Performance Trends

Veridian's reliability data is provided in both tabular and graphical format below for the period 2006 to 2012 inclusive. SAIDI and CAIDI are trending downwards over this time period while SAIFI is trending relatively flat. Veridian's goal is to continue the downward trending on SAIDI and CAIDI and, through emphasis on outage causation analysis, create a downward trend in SAIFI over this cost of service rate application time period. The significant reduction in reliability during 2009 is mostly attributable to a major wind event in Gravenhurst during August of that year. Weather related events were relatively low in 2010 resulting in a dramatic improvement in reliability; however weather events normalized in 2011 resulting in a decrease in reliability statistics. The vastness of Veridian's distribution service territory makes it susceptible to weather events and animal related contacts, especially in the northern and rural service territory areas. Weather hardening and improvements to animal guarding are common recommendations from the internal reliability team following outage causation analysis. Please refer to Exhibit 2, Tab 3, Schedule 5, for additional details on the features of Veridian's distribution system.

	Year	2006	2007	2008	2009	2010	2011	2012
Veridian Total	SAIFI	2.76	1.81	2.41	2.45	1.58	2.426	2.619
	SAIDI	2.54	1.94	2.36	3.69	0.921	2.25	1.891
	CAIDI	0.92	1.07	0.98	1.51	0.579	0.93	0.722

1



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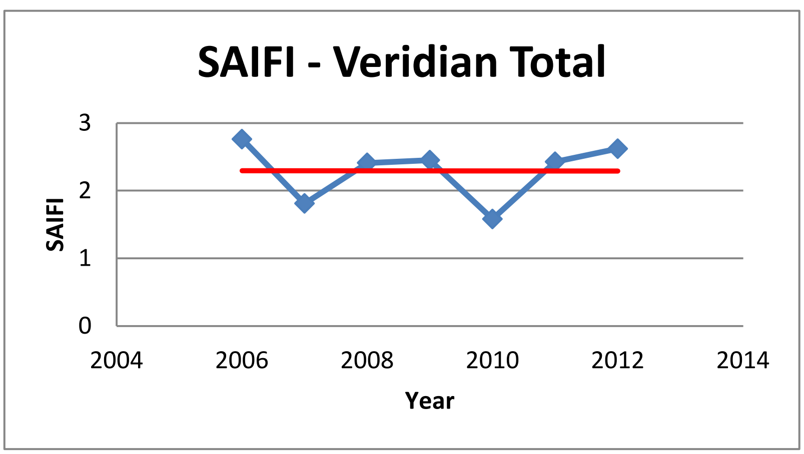

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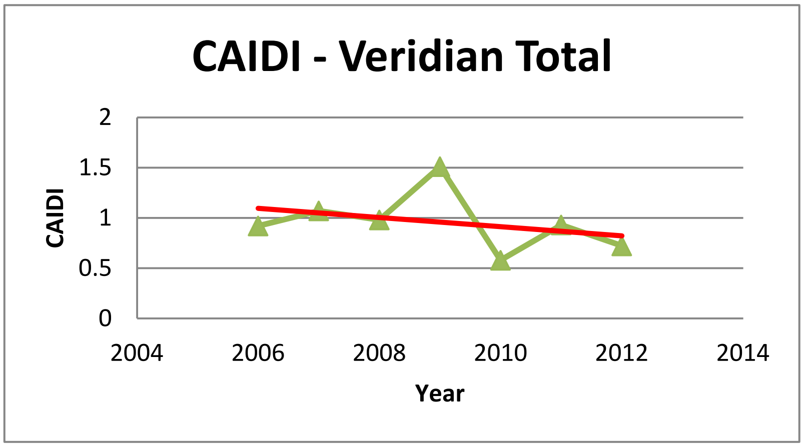


Veridian believes it provides a high value of distribution service reliability and the statistics above indicate a trend of improving SAIDI and CAIDI and a stablized SAIFI for customers. In taking a managed approach to distribution system relaibility, Veridian, through its internal reliability team, will drive continuous improvement in the supply of reliable and quality electricity for its customers.

c) Impacts of System Performance Measures

The results of the performance measures are a contributing factor in determining the direction of the asset management and capital expenditure processes, and have an impact on the capital expenditure plan.

Results from the reliability performance measures in particular have a significant impact where capital investments are planned to occur. Veridian's downward trending on SAIDI and CAIDI year over year is an indicator that the capital investments, as planned and executed are a contributing factor in improving the reliability metrics and confirms the capital spend is succeeding in its desired outcome. Ongoing monitoring and analysis as described previously in this exhibit continue the focus in this critical area.

Results from Veridian's planned inspection and maintenance program contribute as inputs to the asset management and capital expenditure planning process. These results continually update the asset database with the most current information available on the condition of the assets, which is key to making the best informed decisions on next actions. These inspection and maintenance results formed the basis of the initial Asset Condition Assessment (ACA) completed by Kinectrics for Veridian in 2013. Please refer to Exhibit 2, Tab 3, Schedule 4, for further details on Veridian's asset management process, the ACA, and the AMP. The complete ACA study is found in Exhibit 2, Tab 3, Schedule 6, Attachment 1. A cascading effect from the asset management process to the capital expenditure planning process are that the results of the ACA identify which and what assets need attention and/or any necessary actions. The process identifies specific areas or assets that require remedial action for inclusion within the planned programs or as a specific project in the capital expenditure plan, or that additional inspection and maintenance activities are necessary within its O & M programs.

Similarly, results from substation loading and capacity continually update the asset database for Veridian's substations. Monitoring the health of these critical assets occurs on a cyclic basis through inspection and test results, or through on-line real time monitoring by operating staff at Veridian 24/7 System Control Centre. Review and analysis of the loading capacity profile is reviewed monthly by staff and any potential loading capacity issue is identified very early on in the trending and initiates closer scrutiny and monitoring as well as a potential capital investment occurring in the future. Any loading capacity constraints are also flagged which may impact the scheduling of capital project construction. For example, a 13.8kV feeder may not be able to be removed from service for a road relocation project during the summer months as it would add load unto another substation that would exceed its capacity limits as previously described in this document. The project would be scheduled to proceed in the spring or the fall to minimize the capacity impact.

The Standards department maintains and updates records on numerous asset categories and their incidence of failure. As noted, all asset failures are analyzed to determine the root cause of failure. Negative performance trending tracking of failing assets are inputs to the asset management process with results further input into the capital planning process.

Asset Management Process

This section of the Distribution System Plan (DSP) provides a high level overview of Veridian's asset management process.

Key elements of the process that drive the composition of Veridian's proposed capital investments are highlighted along with Veridian's asset management philosophy. The relationship between corporate goals, asset management objectives, and the linkage to the selection and prioritization of Veridian's planned capital investments is explained.

The components of the asset management process that Veridian has used to prepare its capital expenditure plan are identified, including inputs, the data sets, primary process steps and outputs.

The information generally used throughout the DSP is based on available information established between mid-2012 to mid-2013, and should be considered as current.

This is the first DSP to be filed by Veridian, and as such, there are no important changes to the asset management process identified from a previously filed DSP.

Looking forward, the next steps planned to improve Veridian's asset management process have also been identified in as much detail as currently available.

a) Veridian's Asset Management Objectives

Veridian's asset management objectives form the high-level philosophy framework for its capital program. These objectives help to define the content of the programs and the major projects in the capital expenditure plan to be able to sustain Veridian's electrical distribution system. The objectives provide guidance to make effective capital investment decisions, which inherently make the best use of, and maximize the value of the assets to the company. The objectives identify an initial starting point and they will continue to be developed, enhanced, or adjusted as necessary to be aligned with the business environment that the company operates in. The asset management objectives have been qualitatively integrated into Veridian's Capital Investment Process (CIP) to prioritize investments for a number of years including the bridge and test years.

Veridian's asset management objectives are to:

- Construct, maintain and operate all assets in a condition safe to staff, contractors and the public;
- Actively manage distribution assets to optimally balance system investments and reliability;
- Align asset investments with customer expectations of cost, reliability and service performance;
- Satisfy growth and loading needs by managing capacity and asset utilization;
- Continually seek out, develop and deliver sustainable cost efficiencies relating to asset deployment, operations and maintenance;
- Manage the pace of asset investments over the long term, to level customer rate impacts while continuing to deliver economically reliable power to customers; and
- Incorporate and leverage the benefits of new technology.

Veridian's corporate business goals provide direction for the company's vision of the future. Optimizing operational efficiency and effectiveness with improvement through technology is a co-related key theme within these business goals. These goals have specific strategic objectives that apply directly to Veridian's asset management process and its objectives.

Those strategic goals and objectives applicable to asset management have provided a go forward direction for continuously improving the asset management process from its current state and include:

- instituting process re-engineering and cost control programs through:
    - adopting new technologies to support efficiency improvements; and
    - developing a structured optimized reliability based maintenance program.

- establishing and maintaining a capital plan through:
    - developing measurement tools for efficient capital deployment;
    - developing a multi-year asset sustainment plan designed to enhance reliability; and
    - establishing and documenting a capital specific risk management process.

- developing Veridian's Distribution Automation (Smart Grid) through:
    - continuing to integrate Distribution Automation (DA) into its annual capital plans;
    - evaluating and evolving second wave DA technology;
    - leveraging DA technology for continuous improvements in its system reliability.

The first two sets of objectives have translated into an initial Asset Condition Assessment (ACA) deliverable completed in 2013. The Asset Management Plan (AMP) deliverable is currently in development using the ACA as its basis and is planned for completion in 2014. Results of the ACA were incorporated into the 2014 rate application. The completion of the ACA and its results was deemed a key milestone as Veridian transitions into a more structured approach to asset management. Performance assessment and management of risk are aspects included as well that remain to be developed.

The third objective follows a parallel path and is incorporated into criteria for individual projects found within the capital expenditure plan. At Veridian, DA umbrella includes distribution automation with enhanced monitoring and is typically targeted at substations, and/or specific feeder assets, which have a high customer count, poor performance and high SAIDI impact. Benefits include real-time availability of decision-making information resulting in increased speed to fault response, cost efficiencies and reliability improvements. Details on DA can be found in Exhibit 2, Tab 3, Schedule 1 and Exhibit 2, Tab 3, Schedule 7.

Asset Management Process Next Steps

To further strengthen the entire asset management process, Veridian is committed to developing and completing the following components of its asset management process, which at this time do not exist as formal documents but are found qualitatively within the current asset management plans and activities:

Asset Management Policy

The policy will be a high-level over-arching statement of Veridian's asset management direction, principles and mandatory requirements. The policy will interpret the company's Vision, Mission and Values in terms that are reflected in the asset management process. It will serve as the connection between the top corporate goals and objectives through to the bottom asset management practices.

Asset Management Strategy

The strategy will identify how the Asset Management Policy will be achieved, and be the coordinating mechanism to ensure that activities on the assets are aligned to optimally achieve the company's corporate and asset management objectives. Conceptually, the strategy will include items such as; setting out the criteria for optimizing and prioritizing asset management objectives, lifecycle management requirements of the assets, stating the approach and methods by which the assets will be managed, including performance, condition and criticality assessment, the approach to management of risk, identifying continuous improvement initiatives.

Asset Management Plan (AMP)

The plan will outline the asset management practices which are part of an optimized lifecycle strategy for Veridian's distribution system assets. Included will be the programs and major projects required to sustain Veridian's electrical distribution system. Further embedded will be the tasks that need to be completed to meet the asset management objectives. The plan will include the documented planning methodology used and key assumptions made, the different interventions available and the options considered, the specific tasks and activities (actions) required to optimize costs, risk, and performance of the assets, and the means and timelines by which the actions are to be achieved.

Performance Assessment Goals and Objectives

The goals and objectives will be used throughout Veridian's asset management approach and will be embedded within the asset management policy and strategies, and utilized within the plan. Included would be any key tactical initiatives that would help achieve the objectives. The goals and objectives, once identified, will have targets established that will determine the measure of success of the asset management programs and practices. Conceptually, objectives will most likely revolve around, but not be limited to safety, reliability and cost efficiency.

b) Asset Management Process

Overall Approach

Veridian is in the process of transitioning its asset management process from its current state to a more structured approach. Veridian has, and will continue to use its current CIP during the transition as it has been successfully working effectively using many aspects of good utility practice and is being completed within the context of the current, and an expectation of future, customer requirements, the prevailing business and regulatory environment and available resources and technology.

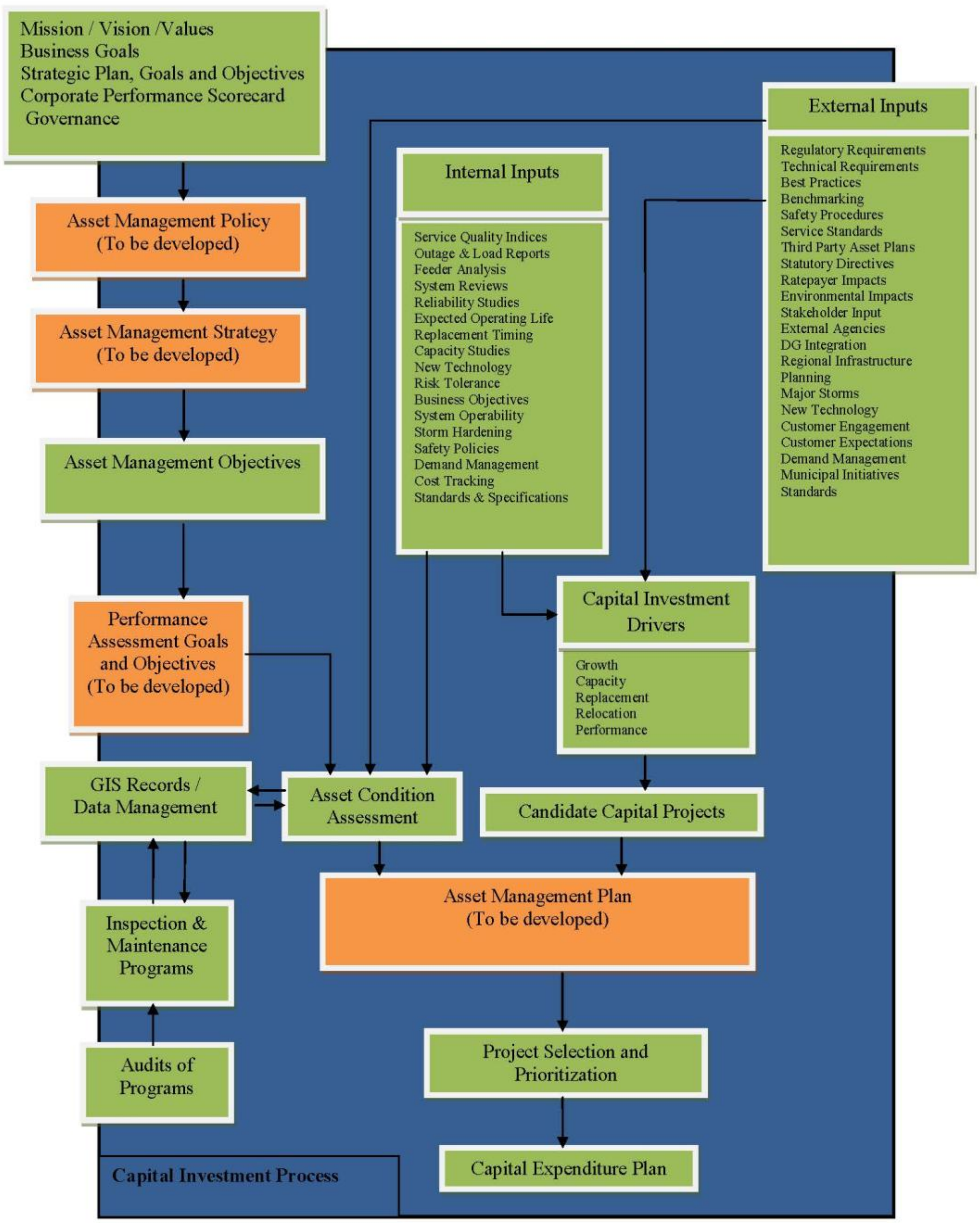
Asset Management Process Flowchart

The flowchart in Figure 1 is intended to illustrate the asset management process in transition, and represents the process that Veridian is currently using as well as progressing towards. The flowchart identifies a process that is an initial starting point which will continue to be developed, enhanced, or adjusted as necessary based on the successes or the needs improvements through its continuous improvement cycle.

Veridian's CIP is shown as the block square, in blue, underneath the multiple coloured blocks. This figuratively and literally represents the solid and successful base upon which the development of the more formal structure of the asset management process has been based upon, and that will continue to be overlaid on top.

The flowchart shows that the significant majority of the green coloured block components are currently in place. The remaining orange coloured block components with the "(To be developed)" comment are blocks have been described previously in this document as to be developed and should be considered as a straight pass-through in the process flow at this time.

Figure 1 Asset Management Process Flowchart



Veridian recognized the opportunity and the need to build on its base CIP to continue to improve its asset management process. Completion of the Asset Condition Assessment (ACA) in mid-2013 was a significant milestone in moving toward this improvement. The results from the ACA did identify some gaps in the condition data for some asset categories. Starting in the test year and going forward, Veridian is committed to filling the parameter and sub-parameter condition characteristic gaps for the asset categories to refine the results of the ACA. Veridian has responded and placed a significant focus on improving the processes, programs, documentations and resources to address these data gaps such as through the augmentation of resources in the asset management area, and additional testing for wood poles and underground primary cable under its O&M programs for the test year and in the following years. The identified criticality of Veridian's municipal substations as key distribution system assets has driven the requirement for increased capital investment in this asset category and the necessity for dedicated resources to address the ACA results.

The transition from the current CIP to a more formal AMP will not require major changes to the planning framework or to the asset management objectives. The main differences will be increased reliance on electronic operating, maintenance and asset data; enhanced coordination between business units and with external stakeholders; and more efficient data collection and management to assess life cycle costs. All of these benefits will be provided with minimal incremental investment by leveraging the efficiencies already developed and in use with the CIP and the company's Geographic Information System (GIS) initiatives.

<u>Veridian's Capital Investment Process (CIP)</u>

Veridian's CIP is the underlying base to its asset management process upon which the more formalized approach will be built.

In KPMG's March 10, 2009 report to the Board, titled *Review of Asset Management Practices in the Ontario Electricity Distribution Sector* (the "KPMG Report"), KPMG referred to a concise definition of asset management to highlight the main elements as: a process to optimize performance, costs and risks relevant to service delivery. This summary definition was supplemented, by five main processes (Inspection, Maintenance, Capital Planning, Capital Financing and Information Management) with four to six key practices for each process to describe an ideal asset management approach, referred to as the "maturity model".

Over the last four years, Veridian has been using its CIP to manage its assets and capital expenditures. Though similar to the process in the KPMG report, Veridian has continued using a less formal hands-on approach as it was found that Veridian's processes were working reliably, safely and cost effectively. However, with the increasing technical complexity in the assets themselves and how they must be operated to meet Veridian's expanding system needs, it was recognized that the current processes (collectively referred to as Veridian's CIP) could be enhanced to improve the efficiency of its asset management process and that Veridian must begin to evolve and transition into a more structured approach to asset planning with the ability to retain and manage increasing amounts of asset, operational and financial data electronically.

In the 2014 test year, Veridian has continued to use its CIP, but also introduced the ACA results into the management of its assets as the company develops a more formal AMP. During the transition from the CIP to its AMP, Veridian has begun to tighten the coordination between its work groups and expanded its data gathering capabilities with improved access to electronic operating, maintenance and asset condition records to ensure that the most accurate information is always available in the company's GIS for data management. These changes have and will continue to steadily improve life-cycle management of assets and enhance risk management, preventative maintenance and planned investment activities. The KPMG Report recognized GIS as a key enabler of asset management and a main repository of distributor asset data.

Veridian's current approach to asset planning continues to cover all five of the key processes identified in the KPMG Report. The conditions of assets are assessed based on field inspections, life expectancy, fault frequency, maintenance costs and customer service impacts. Assets are replaced when required to maintain distribution service and system reliability (non-discretionary expenditures) or when replacement is determined to be more economic from a ratepayer perspective than asset refurbishment and/or ongoing maintenance (discretionary sustainment capital). The ACA study has introduced additional information and considerations to be included in Veridian's asset management process.

Capital spending is driven by capital needs identification. Projects are identified as potential candidates for the budget and the total capital expenditures planned for the year are assessed with regard to previous spending levels, rate impacts, customer service value, shareholder investment and the need to proceed with non-discretionary projects. Once it has been reviewed for these factors, the Capital Plan is submitted to the Veridian Board of Directors for approval along with the proposed financing. The finance plan is assessed to ensure that the OEB deemed equity structure is maintained and there are no adverse impacts on the debt service coverage ratios. The approved capital budget sets the spending envelope for the current year. As such, the budgeting process involves both a bottom-up and top-down approach.

Veridian's overall capital budget spend envelope is set during the annual review but capital spend within the envelope may be adjusted throughout the year to meet changing capital requirements on an as required basis through quarterly reviews. These reviews identify any material dollar reallocations, both increases and decreases to individual approved capital project budgets while maintaining the overall approved capital budget spend envelope intact. For example, capital funds would need to be allocated for a non discretionary spend due to storm damage from extreme weather conditions, or from a road relocation project that had not been previously identified by any of Veridian's municipal or regional road authorities. Any capital project whose detailed engineering design identified a difference between the preliminary planning estimate and the detailed engineering design would also be included.

In general, the overall approach used to select the candidate capital projects to be considered in any year has been consistent. The criteria considered encompasses employee, contractor, and public safety, system reliability, service quality, rate impact, operational efficiency, cost effectiveness, environmental effects, regulatory compliance and stakeholders concerns. Although safety and compliance are prerequisites for all projects, the weighting of the other criteria can vary depending on the current system requirements and the relative impact of each project. Judgment is required when operating under either the current or the proposed planning approach, but in the latter's case, the decision making process will be enhanced by providing better access to system and asset data.

The improved access to system information through the company's GIS, using mobile computing as one example, is expected to enhance the coordination between Veridian's inspection, maintenance and capital processes. Asset management decisions that are currently made based on physical assessments and operating experience will be better informed through electronic access to operational and asset records and by the ability to use this data to provide more accurate lifecycle costing.

A key principle driving the transition will be the development of the AMP that can meet the specific needs of Veridian without imposing unnecessary costs on its customers. As with most service, operational or capital decisions, the value of the asset or service to be acquired must be and will be measured against the initial purchase price, the implementation and on-going maintenance costs, and long term operating costs.

The KPMG Report recognized the benefits of using a distributor specific approach when it concluded that despite the fact that a standard codified approach has not been adopted by the distributors contacted in the review, all of the asset management practices used by the other distributors were at the expected level of maturity with a number of them in a leading position in some areas. The KPMG Report also concluded that the manner in which the distributors apply asset management will vary by distributor, with larger distributors generally requiring more formalized processes. Veridian agreed with this conclusion provided that the more formalized processes meet the evolving needs of the distributor cost effectively. With this in mind, Veridian has decided to build on the efficiencies gained from its current knowledge based approach and transition diligently to a more structured data-based approach to improve the efficiency and cost effectiveness of its asset management program.

Discretionary Capital Projects

All projects not mandated by regulatory, legal or road authority requirements are deemed discretionary. Evaluating the absolute or relative importance of these proposed investments in distribution assets can be an intricate task. There are often competing requirements for available resources in any year, and some selection and evaluation criteria may be quite subjective. In the end the decision whether to proceed with an individual project in the current year is made by senior management based upon the best information available at the time.

To facilitate the decision making on discretionary capital projects, Veridian uses a quantitative scoring scheme based on a range of criteria generally based and including: health and safety concerns; load and customer growth projections; regulatory and environmental requirements;

system reliability; life expectancy; operational efficiency and optimal life-cycle costs. The list of criteria which are detailed below are suitably applied to the specifics of discretionary candidate capital projects and work to convert subjective (qualitative) issues into objective (quantitative) results to aid in project to project comparisons.

Public Safety: considers whether there is any impact on public safety, or, is the project very likely to reduce risk of a public injury or damage over the next 10 years. Where the risk of public safety is known and the probability of occurrence and degree of harm are unacceptable, remedial action is taken and the investment is treated as non-discretionary.

Worker Safety: considers whether there is any impact on worker safety, or is the project likely to reduce risk of a worker injury in the next 10 years. The same approach is used as in the response to public safety concern described above.

Environment – Impairment: considers how much of an impact is there on risk of environmental impairment, and will the project reduce the risk of an environmental incident once every 10 years. The degree of harm, probability of occurrence and financial impact of deferred remediation are to be assessed under this criterion.

Environment – Footprint: considers the project impact on Veridian's environmental footprint, or will it reduce the company's GHG (losses, emissions, wastes, etc.). As a recognized leader in conservation and energy efficiency, Veridian must manage its corporate image in this area very carefully and sets a high standard for its customers to encourage CDM, energy efficiency and renewable generation.

Reliability: considers to what extent the project impacts the power system reliability and customer service. If it will definitely eliminate a sustained feeder outage, the economic benefit can be determined. If the reliability improvement is more global as with redundancy investments, then it is necessary to apply judgment to determine the value of the new assets to its distribution system and its customers.

Power Quality: considers the project impact on the power quality. Veridian is expected to deliver a specific quality of power (voltage, regulation, etc.) and investments required to maintain this level of service can range from non-discretionary where the power standard is not maintained to discretionary when the quality is acceptable.

Customer Satisfaction: considers the project impact on Veridian's ability to maintain or improve ESQRs. At a certain level, investment in this area may be considered non-discretionary when a distributor is ordered to improve its service quality and an asset investment is required. Where the distributor is performing at an acceptable ESQR level, increased investment to enhance service would normally be considered as discretionary spending.

Customer Perception: considers whether the project has a perceived value to the public. This criterion works both ways in that a project may be perceived as having a negative impact on the public, the immediate area or an individual customer. In each case, while customer perception must be considered and appropriately managed as part of any project, perception should not be the only deciding factor.

End of Life: considers whether the asset in question has more than 50% remaining expected life, or, is it at or within 2 years of expected or predicted useful operability. The closer an asset is to its expected obsolescence and/or end of life, the higher the need to replace in order to avoid a service disruption or a safety issue. The replacement of critical assets that have exceeded their life expectancy could be considered as non-discretionary investments in certain situations if there is safety or reliability concerns.

Maintainability: considers whether workers will see an improvement in their ability to maintain the system or the equipment, and will it improve the ease, degree, and frequency of maintenance. Investments that facilitate maintenance, improve employee moral and/or lower maintenance costs should be made as discretionary sustainment.

Operability: considers whether workers will see an improvement in their ability to operate the system or the equipment, and will it improve the ease and flexibility of system operations. Investments that facilitate system operations, improve employee moral and/or lower operating costs should be made as discretionary sustainment.

Table 5 below shows the scoring criteria.

Table 5 – Veridian Capital Investment Process Scoring Criteria

	Criteria	**Minimum Score**	**Minimum Criteria Description (give the minimum score if…)**	**Maximum Score**	**Maximum Criteria Description (give the maximum score if..)**
1	Public Safety	0	There is no impact on public safety.	15	The project is likely to reduce risk of a public injury or damage in the next 10 years.
2	Worker Safety	0	There is no impact on worker safety.	15	The project is likely to reduce risk of a worker injury in the next 10 years.

	Criteria	Minimum Score	Minimum Criteria Description (give the minimum score if…)	Maximum Score	Maximum Criteria Description (give the maximum score if..)
3	Environment-Impairment	0	There is no impact on our risk of environmental impairment.	5	The project is likely to reduce the risk of an environmental incident once every 10 years
4	Environment-Footprint	0	There is no impact on our environmental footprint.	5	The project will or is likely to reduce our contribution to GHG (losses, emissions, wastes, etc.).
5	Reliability	0	There is no impact on the power system reliability we deliver.	10	The project is likely to eliminate a sustained feeder outage.
6	Power Quality	0	There is no impact on the power quality we deliver (voltage, regulation, etc.).	5	The project will have a direct impact on improving power quality.
7	Customer Satisfaction	0	The project has no impact on our ability to maintain or improve our SQR's.	5	The project will allow an improvement in SQR's, or will make achieving them easier.
8	Customer Perception	0	The project will have no perceived value to the public.	5	The project will be recognized by many customers as an improvement.

	Criteria	Minimum Score	Minimum Criteria Description (give the minimum score if…)	Maximum Score	Maximum Criteria Description (give the maximum score if..)
9	End of Life	0	The equipment has more than 50% remaining expected life.	10	The equipment is at or within 2 years of expected or predicted useful operability.
10	Maintainability	0	Workers will see no improvement in their ability to maintain the system or the equipment.	5	Workers will clearly see a significant improvement in the ease, degree, and frequency of maintenance.
11	Operability	0	Workers will see no improvement in their ability to operate the power system.	5	Workers will clearly see a significant improvement in the ease and flexibility of system operations.

Inputs to the Asset Management Process

Veridian uses several sources of data to assess the status of its distribution system assets and to assist in determining the capital and operational investments to be made in the system. The sources of data into the asset management process include:

- Inspection and Maintenance programs;
- Geographic Information System (GIS);
- System Loading vs. Capacity;

- Reliability Information;
- Internal and External Drivers; and
- Asset Condition Assessment (ACA).

Planned Inspection and Maintenance Programs

Veridian maintains a full schedule of distribution asset inspection and maintenance programs operating on a three-to-six year rotation as required by the OEB's Distribution System Code (DSC). Inspection, maintenance and operational data that is collected and recorded in the company's GIS is used to maintain and update the asset source data and support Veridian's operating and capital expenditure plans.

Completion of the inspection and maintenance programs is not only a matter of compliance, but results from the inspection and maintenance programs allow a continual update of the asset database in the GIS. The programs mean that assets are visited regularly and their condition assessed so any necessary actions are taken as promptly as possible in a proactive approach based on what is found, in particular if any safety hazard or concern is identified. Please refer to Exhibit 2, Tab 3, Schedule 6, for details on Veridian's inspection and maintenance programs. As with every other Ontario distributor, Veridian's inspection and maintenance programs are audited on a yearly basis as required by Ontario Regulation 22/04. Veridian has achieved compliance in this portion of the audit each year since the regulation came into effect in 2004.

Geographic Information System (GIS)

Veridian's GIS is the database for all of its distribution assets and serves to be an accurate model of Veridian's physical electrical distribution system. The asset source data in the GIS feeds the ACA process. Details of each asset is collected and updated accordingly. Asset data is input from a multitude of sources including, but not limited to,: constructions as built records, legacy records, annual inspection and maintenance program results, trouble calls, fault information, etc.

As the asset is visited through planned inspections or maintenance, the asset data is verified or corrected. The information in the GIS, such as location, asset ratings or specifics of the asset, installation date, manufacturer or supplier, asset style, last inspection date, last maintenance date, etc., in whole describe the asset. Search and filter functions allows specific fields to identify specific assets based on search criteria. For example, a search for 40 year old pole mount transformers would begin to define the number of transformers in this category that statistically are moving toward the "most likely to fail" group. The search identifies the number as inputs to the capital planned sustainment programs. The locations of the transformers to be replaced, would then allow an efficient plan to be developed for individual replacements or integrated with another planned capital project.

System Loading vs. Capacity

Load forecasting and capital growth planning are and will continue to be the underlying basis for the near and longer-term capital requirements for new or enhanced capacity. The loading and capacity information are inputs to the ACA process as these conditions upon which assets, such as the substation asset categories are assessed and evaluated upon. Information is collected automatically (some manually) on system peak loading at many points in the system, using IESO meters, Veridian supply point meters, and substation feeder and sub-feeder load measurement devices. This data is analyzed as needed in various software applications to measure the risk of system overloading and mitigate any concerns. Veridian's efforts in forecasting these demand based investments are made more challenging due to the numerous distinct and disparate operating districts that Veridian services, that have varying features between them such as differing economic conditions and physical geography. Please refer to Exhibit 2, Tab 3, Schedule 5, for the features of Veridian's distribution system. Veridian makes best efforts to apply its capital investment strategy consistently and equitably across all of the areas that it serves.

Reliability Information

Veridian places a high level of importance on ensuring distribution system reliability meets the expectations of its customers. Veridian strives to continually improve its processes for collecting, measuring, analyzing and utilizing outage information in order to effectively manage distribution system reliability in its service territories. When there has been a failure of an asset, root cause analysis attempts to determine the cause of the failure, and if there is any failure trending requiring targeted plant replacements to try to mitigate any future failures. The failure of the asset is recorded, and the cause inputs to maintain and update the asset source data for assets in the GIS as well as the ACA.

Operations staff monitor distribution system outages on a daily basis and, if these can be correlated with customer complaints, initiates an appropriate level response to address reliability concerns on a more immediate basis rather than waiting until the quarterly review.

On a quarterly basis, the Veridian Reliability Committee meets to formerly analyze outage causation data and make recommendations for reliability improvement. All Veridian feeders are ranked, in terms of their quarterly performance, from worst performing to best performing. Worst performing feeders are analyzed in detail to determine outage causation and the information is utilized to inform Veridian's asset management process and then in turn the O&M programs and capital expenditure plan.

Internal and External Input Drivers

There are a number of internal and external drivers which have an impact and contribute to the asset management process. Table 4 below lists the more prevalent drivers, whether they are external or internal driven, and provides some examples for each. Furthermore, within most driver categories there could be two distinct needs types: non-discretionary for which Veridian has to make an investment to address them, and discretionary for which Veridian has to make decision first whether the need must be addressed immediately, at some future time, or not at all.

Table 4 – Input Drivers to Asset Management Process

Drivers	**External or Internal**	**Examples of Drivers**
Regulatory Requirements	External	Inspections under DSC, ESQR targets, metering
Standards	External	Clearances, PCB content, limits of approach
Asset Condition Assessment	Internal	Age and conditions of current assets, end-of-life replacements, obsolescence
Reliability Studies	Internal	Worst performing feeders, power quality concerns
Capacity Studies	Internal	Load growth, transmitter supply, TS and MS substation and feeder loading
Specific Connection Requests	External	New subdivisions, industrial customers demand increase
Municipal Initiatives	External	Roads widening
DGs Integration	External	FIT, MicroFIT
Regional Infrastructure Planning	External	New Supply Feeders, load transfers
Major Storms	External	Service restoration, assets replacement
Incorporating New Technologies	Internal/External	IEDs, Smart Grid
Conservation and Demand Management	Internal/External	Line losses mitigation, peak shaving, expected results of CDM programs
Customer Engagement	External	Customer feedback through surveys, utility coordinating committees, advisory committees

Risk Tolerance	Internal	Corporate risk tolerance
Customer Expectations	External	Price, reliability
Safety and Environmental Policies	External/Internal	Worker, contractor and public safety, Ministry of Labour, Ministry of Transportation, IHSA
Business Objectives	Internal	Corporate business goals, strategic plan, goals and objectives, governance
Storm hardening	Internal	Voltage conversion, underground construction, upgrade in design standards, increased clearances
System Operability	Internal	SCADA upgrades, additional sectionalizing capabilities

Asset Condition Assessment (ACA)

The ACA involves the collection and interpretation of condition and performance data of key assets, evaluates the condition of the asset, detects and quantifies long-term degradation of the asset, serves as an aid in prioritizing and allocating sustainment resources in order to be able to make informed capital investment decisions. The ACA model receives inputs from a variety of sources as shown on the flowchart in Figure 1 included previously and described above in this document. The result of the ACA is an optimized lifecycle plan based on asset sustainability. In late 2012, Veridian selected and engaged Kinectrics Inc. (Kinectrics) to perform an ACA on Veridian's key distribution assets. Kinectrics has a wide range of experience in assessing the condition of utility assets and their expertise in this area has not only been industry accepted but acknowledged and accepted by the OEB as well. The complete ACA study is found in Exhibit 2, Tab 3, Schedule 6, Attachment 1. For the test year, the results of the ACA were taken into consideration when Veridian selected and prioritized its candidate capital projects to be submitted for approval in the annual budgeting process. It should be noted that results of the ACA as is, for the number and timing of the replacements that was recommended, was strictly from an analysis aspect based on the available data. However, from a practical, reasonable and sustainable aspect, Veridian overlaid its own review and judgement on the results to spread the replacements over a longer period of time to balance and smooth budget and resources impacts. Therefore in some cases, the annual planned proactive replacement numbers that have been included in Veridian's 2014 capital budget will vary from those recommended by the ACA results. As the ACA results continue to be refined, Veridian will continue to use the information from its ongoing proactive inspection and maintenance programs to optimize spending, with priorities and scheduling based on the results. Under the proposed capital planning model, decisions to repair, refurbish or replace existing assets will continue to be based on experienced judgment and knowledge augmented with improved access to electronic records and structured evaluation processes.

Overview of Assets Managed

This section of the Distribution System Plan (DSP) provides a high level overview of the scope and depth of the assets managed by Veridian.

Key features of Veridian's diverse and non-contiguous service area are identified, as are their impacts on Veridian's DSP. Statistical information provides details on Veridian's system configuration, asset types and capacity assessment.

The information generally used throughout the DSP are based on available information established between mid-2012 to mid-2013, and should be considered as current.

Veridian's distribution system is divided into the following five (5) operating districts. The 13 communities served are identified within the brackets:

- Ajax (serving Ajax and Pickering)
- Belleville (serving the City of Belleville)
- Brock (serving Beaverton, Cannington, Scugog (Port Perry), Sunderland and Uxbridge)
- Clarington (serving Bowmanville, Newcastle, Orono and Port Hope)
- Gravenhurst (serving Town of Gravenhurst and area)

Veridian's overall service area is somewhat unique, when compared to other distributors. At 639 square kilometres it is one of the largest in Ontario and also covers dispersed non-contiguous operating districts. In some cases, non-contiguous communities are located within the operating districts themselves. Refer to Exhibit 1, Tab 4, Schedule 9, Service Area or Electricity

Distribution Licence ED 2002-0503 for reference maps. Although overall capital and O&M decisions are made at the corporate level using the asset management process as described in Exhibit 2, Tab 3, Schedule 4, the decisions are driven and are developed in a way that adequately addresses specific investment needs faced by each operating district, i.e., growth vs. sustainment of aging infrastructure challenges that vary from district to district based on their geography, assets condition, and customers mix.

a) Features of Service Area that Impact Veridian's DSP

The high-level asset management and capital planning objectives, found in Exhibit 2, Tab 3, Schedule 4, and Exhibit 2, Tab 3, Schedule 8 respectively, apply in whole to Veridian's total distribution system. The following identify a number of features, the evolution of which, Veridian expects will impact elements of its DSP during the forecast period. For the majority, the evolution, or aging, of these features will directly tie in to Asset Condition Assessment (ACA) results which identify the expected number of assets requiring replacement. Further refinement of the ACA and the development of the Asset Management Plan (AMP), as described in Exhibit 2, Tab 3, Schedule 4, will identify which of the assets associated with these features will need to be replaced during the forecast period. The feature diversity between operating districts will directly impact cost by their very nature. The last two features identify capacity and growth related activities that are considered non-discretionary and that will or may impact assets found within the immediate area of the individual projects.

Table 1 identifies the features of Veridian's Distribution System by district.

1 **Table 1 – Features of Veridian's Distribution System by District**

Feature	Ajax	Belleville	Brock	Clarington	Gravenhurst
Predominantly Rural or Urban	Urban	Urban	Rural	Urban	Rural
Number of Different Primary Voltages	4	3	3	4	3
Primary Voltages Owned and Operated	44kV, 27.6kV, 13.8kV, 8.32kV	44kV, 13.8kV, 4.16kV	44kV, 8.32kV, 4.16kV	44kV, 27.6kV, 13.8kV, 4.16kV	44kV, 12.47kV, 4.16kV
Mostly Overhead or Underground	Combination	Combination	Overhead	Combination	Overhead
Contiguous Service Area Within District	Yes	Yes	No	No	Yes
Assets Location	Road allowances	Road allowances	Road allowances	Road allowances	Road allowances, hydro right of ways in dense bush and forests, islands
Extreme Weather Common	No	No	No	No	Yes
Ground Conditions	Typical urban	Difficult – limestone	Typical urban	Typical urban	Difficult - granite
Submarine Cable	No	No	No	No	Yes
Fast or Slow Growth	Fast	Fast	Slow to none	Fast	Slow
Major Developments	Seaton Community and TS /	Build Belleville program proposed to	--	--	--

Feature	Ajax	Belleville	Brock	Clarington	Gravenhurst
	Highway #407 Extension, Highway #2 Bus Rapid Transit, REG Connections	invigorate the downtown core			

Explanation of Features

Predominantly Rural or Urban – this feature identifies the customer density within the district. It is intended to identify the type of area and communities served compared against each other taking into account other features such as growth, the customer density and the dominant overhead or underground type of distribution system construction. In general, Veridian identifies urban as having a considerable amount of underground servicing installed, relatively high to medium customer density, with generally steady growth year over year. Rural would be identified as having the majority of the distribution assets as overhead construction, low customer density, and slow to no growth year over year.

Number of Different Primary Voltages – this feature identifies the number of and wide variety of assets to be encountered of different voltages, vintages, clearance, styles and installation types that exist and the significant challenges to asset management from and between the diverse predecessor distributors and their legacy construction.

Primary Voltages Owned and Operated – this feature specifically identifies the primary voltages that will be encountered.

Mostly Overhead/Underground – this feature identifies the main type(s), overhead or underground, of construction prevalent in the district for the type of asset replacement or refurbishment to be expected in the future.

Contiguous Service Area – this feature is intended to identify the islands of customers within Veridian's service area and the need for a higher number of substations than typically would be required with an entirely contiguous service area. Overall there is a reasonable effort in capital investments to be self-sustaining from unplanned outages (equipment failures), and planned outages (maintenance) and improvements in power restoration times when assets fail or are damaged. The higher number of substations also requires a higher number of substation assets to be maintained, repaired, replaced or refurbished. The identified criticality of Veridian's municipal substations as key distribution system assets has driven the requirement for increased capital investment in this asset category and the necessity for dedicated resources to address the ACA results.

Asset Locations – this feature identifies the typical locations of the distribution system assets in an effort to indicate the challenges for asset replacement. Challenges typically translate into a higher cost on a per asset basis due to additional travel required, alternate installation method, or similar adder from the typical. For example, the cost to replace a pole off road in rock ground conditions not accessible by a radial boom derrick, but potentially by helicopter only will be greater than replacing a pole on the municipal road allowance in sandy soil that is readily accessible by a radial boom derrick.

Extreme Weather Common – this feature identifies the extraordinary or extreme weather conditions that are expected to have a direct impact on the distribution assets and may impact decision on alternate options for asset replacement. For example Veridian is currently reviewing its overhead design standards to determine the benefits of storm hardening its overhead poles and guying in the Gravenhurst district by upgrading from the typical CSA heavy loading to CSA severe loading criteria. Specifically, the latter criteria adds more ice layering onto the conductors which directly impacts the loading on the poles, which then typically results in a higher class of the poles being required for the installation. The higher class of pole would have higher strength with the expectation being that the poles are able to better withstand extreme weather and so should have a higher survival rate during these events. The final decision is pending, as the analysis has not yet been completed to determine the additional cost benefit of this design change.

Ground Conditions – this feature identifies the extra ordinary ground conditions encountered that are expected to have a direct impact on the replacement of distribution assets through different work methods and equipment required. A higher cost on a per asset basis is expected. In some case, other features such as those described under asset location will layer on additional challenges which translate to expected higher costs.

Submarine Cable – this feature identifies a distribution asset not typically found with the majority of the other distributors. The nature of this feature requires different work methods, equipment and material. These assets, though not specifically identified in the ACA at this time, do require their own specific asset category and have been identified as a data gap that needs to be completed.

Fast or Slow Growth – this feature identifies the districts where there has been increased growth as well as a comparator between districts. Fast growth areas are expected to continue which requires non-discretionary capital investments increasing the competition for capital funds. Assets found within the immediate area of the individual projects will be impacted. The ACA and the AMP will support actions related to these.

Major Developments – this feature identifies significant major developments which are expected to have an impact on the capital investment plan. The Seaton community in north Pickering will require Veridian to complete a business case whether to "build or buy" a transformer station (TS) based on the expected development of this community which is deemed to start in 2015. The available capacity assets at the existing Hydro One owned Whitby TS are planned to be fully utilized first. However, with the timeline of a new TS measured in years, from identified need to in-service, Veridian has already had to start the planning and design for the Seaton TS, as it has been designated, in order to meet its planned 2018 in-service date.

The Ministry of Transportation's Highway #407 expansion from its current end point in Pickering through to the Ajax's district eastern service boundary is currently underway with expectations to be completed between 2013 and 2015. It involves significant asset removal, asset relocations, and new asset construction entirely with multiple millions in gross capital investments as well as a significant commitment of resources for this non-discretionary project, of which there are 13 sub-projects.

The Region of Durham's Highway #2 Bus Rapid Transit (BRT) projects are encompassed under a regional transit priority initiative. It involves the widening of Highway #2 through Ajax and Pickering from 4 lanes to 6 lanes with the additional lanes being for bus transit, and potentially future light rail. The widening will affect several major intersections along its route which will require significant relocations of Veridian's existing overhead assets. The Region's target for completion is March 2016.

Build Belleville is an ongoing municipal infrastructure renewal program targeting the City of Belleville's roads and bridges, water and sewage assets. The various municipal projects included are at preliminary stages in the design process and the associated road works will require significant relocations of Veridian's existing overhead assets.

There is one distribution system expansion is required to accommodate the connection of REG projects during the test year of 2014. The particular project is for an application for a 25.012 MW generation facility in Ajax, scheduled for connection during 2014.

All individual projects for the 2014 test year are found in Veridian's capital expenditure plan.

b) Summary Description of System Configuration

Table 2 below provides a high level summary description of Veridian's system configuration. Circuit lengths are as of December 2012.

Table 2– High Level Summary Description of Veridian System Configuration

Veridian System Features		#of Feeders	Length (km)
Annual electricity delivered	2,707 GWh	185	2561
Peak demand	531 MW		
O/H kms by primary voltage level			
44kV (# of feeders and length (km))	---	23	239.76
27.6kV	---	10	257.06
13.8kV	---	70	432.13
12.47kV	---	7	197.92
8.32kV	---	6	137.89
4.16kV	---	69	195.63
U/G kms by primary voltage level	---		
44kV (# of feeders and length (km))	---	23	6.74
27.6kV	---	10	280.49
13.8kV	---	70	689.43

Veridian System Features		#of Feeders	Length (km)
12.47kV	---	7	47.23
8.32kV	---	6	8.24
4.16kV	---	69	69.09
of MSs	53	---	---
# of MS transformers	65	---	---
# of TSs	0	---	---
# of TS transformers	0	---	---
# of Supply points (TSs)	11		

c) Asset Types, Age and Condition

The decisions regarding capital investments necessary to sustain the existing aging infrastructure, particularly related to the end-of-life replacements, will largely be based on the results of the Asset Condition Assessment (ACA). The ACA was completed by Kinectrics Inc., and data was compiled between August 2012 and June 2013. The ACA will serve as the basis in developing Veridian's Asset Management Plan (AMP). Please refer to Exhibit 2, Tab 3, Schedule 4, for Veridian's asset management process.

Table 3 provides a snap shot overview of the ACA results of Veridian's major asset types. The number of assets whose conditions was assessed was either based on the entire total for the assets in that type, as for substation transformers and substation breakers, or on a representative sample size for the remaining asset types. Results from the sample size would then be extrapolated to the entire asset population based on asset attributes.

Results are historically based on inspection, maintenance and failure records. Please refer to Exhibit 2, Tab 3, Schedule 6, Attachment 1, for the complete ACA study.

Table 3 – Veridian Major Asset Categories and ACA Results Overview

Major Asset Type	Asset Total or Sample Size	Average Age	Average Health Index	Condition of Assets	Number of Poor and Very Poor Units
Substation Transformers	79	29	62%	Poor	16
Substation Circuit Breakers	141	28	72%	Good	7
Wood Poles	28000	28	87%	Good	28
Pole Mounted Transformers	7661	24	94%	Good	106
Overhead Line Switches	1968	9	66%	Good	225
Pad Mounted Transformers	8722	20	94%	Good	134
Vault Transformers	10	7	82%	Good	0
Submersible Transformers	24	15	99%	Good	0
Pad Mounted Switchgears	221	16	83%	Poor	18
Underground Cable	1595	20	76%	Poor	202

Of the asset categories assessed, the substation asset groups (substation transformers, substation breakers) and wood poles had sufficient data and information to better describe the condition of these assets. The other asset groups: pole mounted transformers, overhead line switches, pad mounted transformers, vault transformers, submersible transformers, pad mounted switch gear and underground primary cable had limited asset condition information available other than age, and so the ACA study results and the basis to replacement these assets are mainly driven by age.

Even though Veridian is currently meeting the inspection requirements as mandated by the Distribution System Code (DSC), it is recognized that additional information is required to further refine the ACA output results and therefore adjust the capital investments quantities to manageable and sustainable levels year over year both from a financial and a resource aspect. For the test year, the results of the ACA were taken into consideration when Veridian selected and prioritized its candidate capital projects to be submitted for approval in the annual budgeting process. It should be noted that results of the ACA as is, for the number and timing of the replacements that was recommended, was strictly from an analysis aspect based on the available data. However, from a practical, reasonable and sustainable aspect, Veridian overlaid its own review and judgement on the results to spread the replacements over a longer period of time to balance and smooth budget and resources impacts. Therefore in some cases, the annual planned proactive replacement numbers that have been included in Veridian's 2014 capital expenditure plan will vary from those recommended by the ACA results.

Veridian's long-term sustaining plans, both capital and O&M, also take into account other drivers, such as obsolescence, e.g. lack of spare parts or incompatibility with the new technology, system growth, municipal initiatives, etc., and have the replacement philosophy of addressing future load growth or system needs at the time of replacement rather than strictly replacing assets on a like-for-like basis. Although the sustaining needs typically trigger investments under "System Renewal" Investment Category, the resultant projects/activities may in some cases also address needs under the "System Access" and "System Service" Investment categories.

d) Adequacy of Existing System Capacity

Satisfying growth and load needs is an identified Veridian asset management objective. Please refer to Exhibit 2, Tab 3, Schedule 4, for Veridian's asset management objectives.

Unlike sustaining investments, capital investment needed to address capacity constraints are determined on a district by district basis. Please refer to Exhibit 2, Tab 3, Schedule 8, for further details on planning criteria. Veridian's multiple districts add a level of complexity as they are non-contiguous where supply capacity cannot be easily reconfigured between districts. Veridian is supplied from 11 Transformer Stations with each district essentially being a supply island onto itself. Please refer to Exhibit 1, Tab 4, Schedule 9, Attachment 1, for Map of Distribution System.

Capacity needs for each operating district are assessed from three (3) perspectives:

- Capacity of Veridian's Municipal Substations (MSs) - this aspect of Veridian's capacity needs is based on substation and feeder loading records and through analysis by Veridian's system planning staff. Appropriate measures are determined by Veridian.

- Supply feeders capacity at 44kV or 27.6kV connected to the high side of MSs:
    - Supply feeders that are not entirely dedicated to supplying Veridian but to other distributors - this aspect of Veridian's capacity needs is expected to be addressed within the scope of the OEB's Regional Infrastructure Plan (RIP).

    - Supply feeders that are entirely dedicated to supplying Veridian - this aspect of Veridian's capacity needs is based on substation and feeder loading records and through analysis by Veridian's system planning staff. Appropriate measures are taken are determined by Veridian.

- Capacity of Transformer Stations (TSs) - capacity is provided by Hydro One (transmission) - this aspect of Veridian's capacity needs is expected to be addressed within the scope of the upcoming RIP. Through a combination of system planning between the transmitter and the distributor, capacity needs are identified through a need or in-service date. Planning meetings specific to Veridian occur on a bi-yearly basis and work to identify any issues directly related to capacity as well as any other issues that need discussion and possible actions between the transmitter and the distributor such as any reliability or power quality issues that affect Veridian's customers. The most cost-effective solution is then selected which could involve increasing capacity of the existing facilities, transferring load transfers different facilities, constructing new facilities or some combination of these. Since some of Veridian's operating districts include different geographical areas and/or have supply feeders operating at different voltages, the analysis of capacity needs and the corresponding actions for these districts is done at granularity level below the operating district.

Please refer to Exhibit 2, Tab 3, Schedule 2, for details on Coordinated Planning with Third Parties.

Capacity needs typically trigger investments under the "System Service" Investment Category but the resultant projects/activities may in some cases also address needs under the "System Renewal" and "System Access" Investment categories.

Please refer to Exhibit 2, Tab 3, Exhibit 1, for details on drivers of capacity.

Table 4 summarizes the degree to which the capacity of existing system assets is utilized in each of Veridian's 5 operating districts.

Table 4 – Capacity Utilization at Veridian Operating Districts

Feature/District	Ajax (Ajax and Pickering)	Belleville	Brock (Beaverton, Cannington, Scugog, Sunderland and Uxbridge)	Clarington (Bowmanville, Newcastle, Orono, and Port Hope)	Gravenhurst
% of MS Planning Capacity used	95%	95%	Sunderland - 50%	Bowmanville 13.8 kV-95%	
			Scugog – 100%	Newcastle 13.8 kV-150%	12.47 kV-60%
			Uxbridge – 100%	Newcastle 4.16 kV-10%	
			Cannington – 50%	Port Hope 27.6 kV-95%	4.16 Kv-150%
			Beaverton – 50%	Port Hope 4.16 kV-90%	
Need date for additional MS capacity	2014 - Pickering	2015	Not required in District		
					12.47 kV-2018
				Port Hope 27.6 kV-2018	4.16 kV-N/A
Supply Feeders Voltages	44 kV and 27.6 kV	44 kV	Embedded in H1 supply	44 kV (Clarington and Port Hope)	Embedded in H1 supply

Feature/District	Ajax (Ajax and Pickering)	Belleville	Brock (Beaverton, Cannington, Scugog, Sunderland and Uxbridge)	Clarington (Bowmanville, Newcastle, Orono, and Port Hope)	Gravenhurst
% of supply feeders capacity use	44 kV – 100% 27.6 kV – 75%	100%	To be determined by Regional Planning studies	To be determined by Regional Planning studies	To be determined by Regional Planning studies
Need date for additional supply feeders capacity/load transfers	44 kV - 2013 27.6 kV - 2018	To be determined by Regional Planning studies	To be determined by Regional Planning studies	To be determined by Regional Planning studies	To be determined by Regional Planning studies
% of allocated TS capacity used	84%	To be determined by Regional Planning studies	To be determined by Regional Planning studies	To be determined by Regional Planning studies	To be determined by Regional Planning studies
Need date for additional TS capacity	2018	To be determined by Regional Planning studies	To be determined by Regional Planning studies	To be determined by Regional Planning studies	To be determined by Regional Planning studies
Planning Region and Group	6-Metro Toronto 10-GTA East	12-Peterborough to Kingston	3-GTA-North	10-GTA East	13-South Georgian Bay/Muskoka

Asset Lifecycle Optimization Policies and Practices

This section of the Distribution System Plan (DSP) provides a high level overview of the Veridian's asset lifecycle optimization policies and practices.

The philosophy behind Veridian's approach to decision making on asset replacement and refurbishment is included, and how the completion of the Asset Condition Assessment (ACA) is integrated in the transformation of Veridian's current asset management process.

Veridian's ACA, its results, and how these have translated into its program of planned asset sustainment for the test year capital expenditure plan is described in detail as are its routine inspection and maintenance programs that work to continually sustain existing assets.

a) Veridian's Lifecycle Optimization Approach

Historically, Veridian has made its investment decisions for sustaining its existing distribution assets by weighting capital and O&M costs and risks, against reliability and impact to customers using a qualitative less formal hands-on approach to lifecycle optimization.

This approach considered:

- when the asset should be replaced;

- whether the asset should be replaced or was it better to refurbish the asset (if the asset could be refurbished) and thus defer replacement; and
- what were the prudent and reasonable preventative maintenance activities that would possibly allow the asset to achieve its intended lifespan or perhaps even extend it.

The absolute or relative importance of any proposed system renewal investment in distribution assets can be an intricate task at times. While much of the cost and data assessments in whether to replace or refurbish can be automated (quantitative), other criteria are quite subjective (qualitative). In the end the scoring and rank of a project and/or the decision whether to refurbish or replace an asset in a specific year was made by Veridian staff with the best information available at the time, by blending the quantitative and qualitative together, based on experienced judgment, good utility practice and knowledge augmented with asset data.

Though Veridian's approach and processes have been working reliably, safely and cost effectively, the company recognized that its current processes could be enhanced to improve the efficacy and efficiency of its asset management processes through a transition to a more structured approach to asset planning. The ability to retain, manage and analyze ever increasing amounts of asset, operational and financial data electronically being one desired outcome. Included in the process would be the conversion of the subjective (qualitative) aspects into more quantitative values to aid in producing comparable and repeatable results year over year to enhance and refine the human oversight that is still required.

Asset Condition Assessment (ACA)

Veridian engaged an independent third party, Kinectrics Inc., (Kinectrics) to perform a formal Asset Condition Assessment (ACA) of its major asset categories. This represented a major step forward from a continuous improvement perspective as it allowed Veridian to begin to transition from its qualitative approach to a more quantitative approach in making lifecycle decisions using the results of the ACA as input into Veridian's asset management process. Kinectrics began the ACA in August 2012 and was completed in June 2013. Veridian has used the ACA study in its decision-making for the system renewal projects in its 2014 capital expenditure plan and a basis going forward for the planning window of 2015 to 2018. The ACA as it applies to Veridian's asset management process can be found in Exhibit 2, Tab 3, Schedule 4. The complete ACA study is Attachment 1 to this schedule.

Veridian's key distribution assets have been divided into the following asset categories:

- Substation Transformers
- Substation Breakers
- Wood Poles
- Pole Mounted Transformers
- Overhead Line Switches
- Pad Mounted Transformers
- Vault Transformers
- Submersible Transformers
- Pad Mounted Switchgear
- Underground Cables

For each asset category, the ACA included the following tasks:

- Gathering relevant condition data;
- Developing a Health Index Formula;
- Calculating the Health Index for each asset;
- Determining the Health Index distribution;
- Developing a 20-year condition-based Flagged-For-Action Plan; and
- Identifying and prioritizing the data gaps for each group.

The Health Index quantifies the asset's condition based on numerous operating condition parameters which relate to the long-term degradation factors that in turn cumulatively lead to an asset's end of life. The Health Index is an indicator of the asset's overall health, relative to a brand new asset, and is given in terms of percentage, with 100% representing an asset in brand new condition.

Once the Health Index was calculated for all asset categories, a Flagged-For-Action Plan based on asset condition was developed. For 2014, the results of the ACA study provided a condition-based foundation for making investment decisions related to sustaining Veridian's existing assets. Specifically, the ACA identified, for each of the asset categories, a subset of assets "flagged for action" at the present time and, expected to be "flagged for action" in the future. This plan serves as the input to planning for the capital investments required for asset replacement over the next 20 year period. The number of units "flagged for action" in each year was estimated using either *reactive* or *proactive* approach.

Table 1 below shows the summary of the Health Index evaluation results.

Table 1 Health Index Results Summary

Asset Category	Population	Sample Size	Health Index Distribution (Units)					Total in Poor and Very Poor	Average Health Index	Average Data Availability Indicator	Average Age
			Very Poor (< 25%)	Poor (30 - < 50%)	Fair (50 - < 70%)	Good (70 - < 85%)	Very Good (>= 85%)				
Substation Transformers	79	75	9	7	12	10	37	16	62%	50.2%	29
Substation Breakers	141	129	1	6	10	6	106	7	72%	57.2%	28
Wood Poles	28000	1538	0	28	145	257	1108	28	87%	98.0%	28
Pole Mounted Transformers	7661	3754	41	65	108	219	3321	106	94%	19.0%	24
Overhead Line Switches	1968	646	126	99	118	9	294	225	66%	14.3%	9
Pad Mounted Transformers	8722	8143	102	32	467	258	7284	134	94%	67.1%	20
Vault Transformers	10	7	0	0	1	0	6	0	82%	28.0%	7
Submersible Transformers	24	24	0	0	0	0	24	0	99%	40.0%	15
Pad Mounted Switchgear	221	217	9	9	14	20	165	18	83%	24.9%	16
Underground Cables*	1595	1470	42	160	288	434	546	202	76%	92.2%	20
* cable length, in km											

Since the condition of some assets were derived from limited and sometimes minimal data, the ACA results identified a significant front-end wave of capital spend in 2014 (year 1 of 20) in an attempt to replace those assets in very poor and poor condition immediately and then smooth the capital spend for the remaining 19 years.

Of the asset categories assessed, the substation asset groups (substation transformers, substation breakers) and wood poles had sufficient data and information to better describe the condition of these assets. The other asset groups: pole mounted transformers, overhead line switches, pad mounted transformers, vault transformers, submersible transformers, pad mounted switchgear and underground primary cable had limited asset condition information available other than age, and so the ACA study results and the basis to replacement these assets are mainly driven by age. Even though Veridian is currently meeting the inspection requirements as mandated by the Distribution System Code (DSC), it is recognized that additional information is required to further refine the ACA output results and therefore adjust the capital investments quantities to manageable and sustainable levels year over year both from a financial and a resource aspect.

For the test year, the results of the ACA were taken into consideration when Veridian selected and prioritized its candidate capital projects to be submitted for approval in the annual budgeting process. It should be noted that results of the ACA as is, for the number and timing of the replacements that was recommended, was strictly from an analysis aspect based on the available data. However, from a practical, reasonable and sustainable aspect, Veridian overlaid its own review and judgement on the results to spread the replacements over a longer period of time to balance and smooth budget and resources impacts. Therefore in some cases, the annual planned proactive replacement numbers that have been included in Veridian's 2014 capital expenditure plan will vary from those recommended by the ACA results.

Table 2 below shows the condition-based Flagged-For-Action Plan for the first year and the Veridian staff adjusted results.

Table 2 Year 1 Levelized Condition-Based Flagged-For-Action Plan

Asset Category	Condition-Based Flagged-For-Action Plan for Year 1 based on ACA Results [Number of Units]	Condition-Based Flagged-For-Action Plan for Year 1 based on Veridian Staff Adjusted Results
Substation Transformers	13	3
Substation Breakers	6	3
Wood Poles	528	250
Pole Mounted Transformers	116	110
Overhead Line Switches	299	7 LIS
Pad Mounted Transformers	206	70
Vault Transformers	0	0
Submersible Transformers	0	0
Pad Mounted Switchgear	8	8
Underground Cables*	78	12.5
*cable length in km		

Reactive/Proactive Approach to Assets

In the ACA and as noted above, the number of units “flagged-for-action” in each year was estimated using either *reactive* or *proactive* approach. The reactive approach is based on expected failures per year, whereas in the proactive approach, units are considered for replacement prior to failure. Both approaches consider asset failure rate and probability of failure.

Reactive Approach

The assets categories that are typically replaced reactively include the following:

- Pole mounted transformers
- Overhead line switches
- Pad mounted transformers
- Vault transformers
- Submersible transformers
- Pad mounted switch gear

The predominant practice for the assets in the above categories with a relatively small consequence of failure, are generally replaced reactively when they fail. The assets in these categories are inspected and maintained but are not removed and refurbished when they fail. It is more cost effective, and a more efficient use of resources to replace the asset outright even if the asset is not at the end of its useful life, rather than return in a second visit to re-install the original, and now refurbished, asset in the same location. For example, a 35 year old pole mount transformer that fails will be replaced with a new pole mount transformer on the same pole. The 35 year old transformer will not be refurbished but will be scrapped. In general, this is typical for the other asset categories as well.

Veridian will continue to maintain a reactive program of unplanned sustainment within its capital expenditure plan for the test year to replace the assets that actually do fail, or those that need to be replaced due to their poor condition, before they fail or if they pose a safety risk to the public or workers. The latter group are identified through inspections and preventative maintenance activities such as visual inspections, infra-red surveys and dry ice cleaning. Additional activities such as insulator washing, adding polymeric lightning arrestors, installing animal guards, etc., will also ensure that the asset can remain in service for the expected number of years or longer and would be considered activities and upgrades that are low cost but that can have an improving effect on system performance and reliability over time.

Based on the ACA, the long-term plan for such assets is based on the failure rate particular to each asset category with the expectation that some of the units will fail prior to their typical end-of-life (EOL) and some will continue to operate beyond their EOL. The projected "flagged-for-action" plan is used to estimate a number of future EOL failures without identifying specific units that are expected to fail. In the test year, Veridian has implemented an ongoing proactive program of planned sustainment to replace an identified quantity of these assets before they fail. The proactive program not only allows Veridian to better plan for future replacements, it avoids a future bow wave of replacements, thereby smoothing financial impacts year over year as well as mitigating reliability problems by eliminating the assets most likely to fail sooner rather than when they actually fail. Prior to the test year, and the completion of the ACA, Veridian has managed a proactive program of planned sustainment to replace the assets in the substation transformers, substation breakers, wood pole, pad mounted switchgear and underground primary cable categories. In the test year, the pole mounted, pad mounted, submersible and vault transformer, and overhead switch asset categories have been included to further take advantage of the benefits realized from its current proactive programs.

Proactive Approach

The assets categories that are typically replaced proactively include the following:

- Substation transformers
- Substation breakers and reclosers
- Wood poles
- Pad mounted switch gear
- Underground cables

Assets with a significant consequence of failure are dealt with proactively so that some action is taken before they fail. The assets in these categories are inspected and maintained and may be considered for replacement, refurbishment, or other actions.

Historically, decision making has typically been made as has been described previously in this document. The decision on the appropriate action is considered qualitatively and based on the action's cost effectiveness, for example in deciding what makes more sense, to replace or refurbish an asset, what is the effectiveness of refurbishment vs. replacement (how good relative to a brand new asset will the asset be after refurbishment) and the relative cost of refurbishment vs. replacement. Decisions to repair, refurbish or replace existing assets have been made on experienced judgment, good utility practice and knowledge augmented with asset data.

Based on the ACA, the "flagged-for-action" plan for these asset categories will take into account their condition and associated probability of failure. Furthermore, for substation transformers and circuit breakers, a quantification of their criticality is also taken into account so that urgency of action is then prioritized based on the resultant risk of failure that combines probability of failure and criticality. Once "flagged-for-action" units are identified, the appropriate course of action is then determined. This action could be either:

- replacement,
- refurbishment,
- system re-configuration, that there is a change that eliminates their need,
- having spare units available, or
- no action (do nothing).

Table 3 below shows Veridian major distribution assets categories and indicates, for each category, whether the assets are dealt with reactively or proactively, from a historic and a go forward approach, and whether they are subjected to preventative maintenance practices.

Table 3 – Veridian Assets: Reactive vs. Proactive Approach

Asset Category	Historic Approach	Forward Approach	Preventative Maintenance
Substation Transformers	Proactive	Proactive	Cyclic testing, infrared inspections (where safe to access) and visual inspections
Substation Breakers and Reclosers	Proactive	Proactive	Cyclic testing, infrared inspections (where safe to access) and visual inspections
Wood Poles	Proactive/ Reactive	Proactive/ Reactive	Testing and visual inspections
Pole Mounted Transformers	Reactive	Proactive/ Reactive	Visual Inspections
Overhead Line Switches	Reactive	Proactive/ Reactive	Visual and infrared inspections, switch maintenance program
Pad Mounted Transformers	Reactive	Proactive/ Reactive	Visual inspections
Vault Transformers	Reactive	Proactive/	Visual inspections

Asset Category	Historic Approach	Forward Approach	Preventative Maintenance
		Reactive	
Submersible Transformers	Reactive	Proactive/ Reactive	Visual inspections
Pad Mounted Switchgear	Proactive/ Reactive	Proactive/ Reactive	Visual inspections and dry ice cleaning
Underground Cable	Proactive/ Reactive	Proactive/ Reactive	Will start testing in 2014

Next Steps

Going forward as part of its continuous improvement process, Veridian plans to quantify such asset assessments in the future. The ACA identified data gaps in the parameters for each of the asset categories (ACA inputs), that when updated, will improve the quality of the results (ACA outputs). Continuing to fill in the parameter and sub-parameter characteristics for the asset categories will refine the results of the ACA thereby enabling decisions fully supported by the data.

These data gaps directly tie in with a proposed increase in both capital spend, for developing the remedies to the data gaps, as well as proposed new O&M programs to complete the data gathering to fill the data gaps. Examples include additional testing for wood poles and for underground cables. Veridian is already committed to work with Kinectrics over the next three years (2014-2016) to continually update the ACA from the initial deliverable product in September 2013 through to assisting in developing an Asset Management Plan (AMP) planned for completion in 2014.

As noted previously in this document, Veridian overlaid its own review and judgement on the results to spread the replacements of assets over a longer period of time to balance and smooth budget and resources impacts resulting that in some cases, the annual replacement numbers that were actually included in Veridian's 2014 capital budget will vary from those recommended by the ACA results. As the ACA results continue to be refined, Veridian will continue to use the information from its ongoing proactive inspection and maintenance programs to optimize spending, with priorities and scheduling based on the results.

Veridian Preventative Maintenance Practices

Most of Veridian's preventative maintenance practices involve Time Based Maintenance (TBM) activities which includes periodic less intrusive inspections and more intrusive but less frequent testing that usually requires the units to be removed from service while the testing is being performed. In addition to TBM, Veridian performs additional maintenance that is based on the results of reliability studies and involves actions aimed at improving reliability performance at identified locations that contribute disproportionately to system unreliability.

Veridian's preventative maintenance activities meet the requirements stipulated in the OEB's Distribution System Code (DSC). Following is a more detail description of Veridian's preventative inspection and maintenance activities and programs.

Inspection Programs

44kV Customer-Owned Substation Inspection: Customer-owned 44kV connected substations are inspected annually by Veridian staff to confirm that no deficiencies exist that may be a concern to public safety or a threat to Veridian's 44kV system. The strictly visual inspections are completed by Veridian staff, who do not perform any maintenance work at these facilities. The substations remain energized while being inspected for any of the following items (not a complete listing): signs of oil leaks, rust holes or other signs of physical degradation of equipment, such as damaged porcelain arrestors and insulators, that proper grounding is visible, fencing is intact and vegetation is being managed within the substation enclosure. Action items highlighted from these inspections are forwarded to the customer for follow up remedial action. Veridian offers one free isolation per year during working hours as an opportunity to correct any deficiencies but it is left up to the customer to coordinate based on their best scheduling.

Infra red Scanning: Veridian utilizes contracted services to perform an infra red scan of all three-phase lines in its system annually. This scan inspects all attached components to the three-phase lines as well as a scan of outdoor style Veridian owned substations. The scanning is completed by a contractor who is accompanied by a Veridian staff member who acts as a guide and driver and who also is able to report and react swiftly should there be an abnormal condition discovered with possible impact to public or staff safety or to system reliability. Any incidents of equipment identified as having a suspect heat profile are flagged for investigation and possible repair or replacement.

Based on Veridian's experience with failing switches in 2012, the infrared inspection program has been expanded in 2013 to include approximately 30 additional locations of single phase switches identified as possible significant risk of failure. The expanded program will be continued in the test year.

Single-Phase, Three-Phase Pad mount Transformer and Transformer Vault Inspections: Pad mount and vault transformers are inspected on a 3 year cycle while remaining energized. Inspections for any signs of oil leaks, rust holes or other signs of physical degradation as well as confirming that proper nomenclature is clearly visible on the outside of the unit to assist in trouble call activities. Action items are highlighted from these inspections for follow up. The inspections are completed by Veridian staff.

System Patrol: For system patrol purposes, Veridian's districts are each divided into three sub-sections. In this manner system patrol activities are completed with a 3 year interval. System patrol activities involve a visual inspection of all overhead plant and include immediate correction of safety-related deficiencies and flagging of less serious deficiencies that can be corrected through subsequent planned work. The patrols are completed by Veridian staff.

Maintenance Programs

Overhead Line Maintenance

This is a high level group of many sub-programs including:

- Insulator Washing
- Overhead Pole Maintenance
- Overhead Switch and Conductor Maintenance
- Vegetation Maintenance
- Wood Pole Testing

Insulator Washing: In areas of close proximity to major highways in Ajax, Belleville and Clarington districts, insulator washing is conducted to remove salt and other contaminants in the spring of each year. This work is conducted with the circuits remaining energized with a competent contractor and also includes a visual inspection to help identify other concerns noted while the contractor staff are aloft to perform the cleaning.

Overhead Pole Maintenance: This program includes activities such as replacing damaged insulators, straightening poles, cross arm changes, replacing and repairing broken guy wires and anchors, and similar types of actions. The maintenance work is completed by Veridian staff.

Overhead Switch Maintenance: Scheduled, time based, maintenance programs are completed for overhead switches (gang operated and solid blade) in Veridian's distribution system. The switches are scheduled in a 3 year cycle in order to ensure continued proper mechanical and electrical operation. The maintenance work is completed by Veridian staff.

Vegetation Management: Vegetation Management programs take two forms - one scheduled and one reactive. The scheduled program generally follows a time based interval of three years. The reactive or spot line clearing work is performed as a result of calls from customers or staff, in response to outage reports and reliability trends as identified by Veridian's internal reliability team. While some of the spot work is performed by Veridian staff, the majority of this work and all cycle work is completed by competent contractors on behalf of Veridian.

Wood Pole Testing: In 2012 Veridian tested 1,500 poles as part of its wood pole testing program.

Test results are reviewed for urgent replacement recommendations and will be used to determine if larger scale line rebuilds are required in particular areas due to poor overall pole condition.

Veridian has approximately 28,000 wood poles in service. There are currently significant data gaps in the information Veridian has on the condition of its poles. These data gaps will be reduced through additional testing. The number of wood poles to be tested will be increased in the test year to 8,300.

Veridian does not plan to change the nature of these program activities but rather the magnitude or volumes within the program.

Underground Line Maintenance

This is a high level group of many sub-programs including:

- Switchgear Maintenance
- Transformer and switchgear painting

Switchgear Maintenance/Dry Ice Cleaning: Beginning in 2010, Veridian began to use dry ice cleaning as an improved alternative to air insulated pad mount switchgear inspection. Switchgear are cleaned using this method on a three year cycle. Dry ice cleaning is an abrasive cleaning technique that can remove debris and dirt from the interior of the equipment that may lead to tracking and ultimately failure of the switchgear. A significant benefit of dry ice cleaning over manual cleaning is the ability to perform the work while the switchgear remains energized, when completed by a competent contractor. During the same servicing, an infra red inspection is conducted after cleaning. This inspection can identify remaining hot spots/areas of concern that were not improved with the cleaning operation. These cleaning/inspection reports are utilized by line staff in determination of component or full switchgear replacement.

Transformer and Switchgear Painting: Veridian maintains an annual program of transformer and switchgear painting in all districts as a means to extending the life of those assets. Candidates for painting are identified through the transformer inspection programs as well as customer and staff input.

Station Maintenance Programs

These programs involve a high number of critical assets. Veridian's distribution system consists of fifty-three (53) distribution substations spanning over twelve (12) non-contiguous service areas.

Substation maintenance programs include both schedule maintenance and reactive repair work. Scheduled maintenance activities are conducted on a 3 year cycle and include dissolved gas analysis, full electrical checks completed while station is de-energized, confirmation of cable insulation values, checking of mechanical condition of moving parts and electrical testing of transformers to ensure proper electrical performance. Maintenance activities are performed using a combination of in-house staff and contracted services.

General facilities repairs and contracted services for property and grounds maintenance such as snow removal and grass cutting are also included in these programs.

b) Asset Life Cycle Risk Management

Overall, Veridian has continued to use its existing asset management processes (CIP) as described in Exhibit 2, Tab 3, Schedule 4, for its capital expenditures and incorporated the risk components found within each of the 11 selection criteria as its ongoing practice. To facilitate the decision-making on discretionary capital projects, Veridian uses a quantitative scoring scheme based on a range of criteria generally based and including: health and safety concerns; load and customer growth projections; regulatory and environmental requirements; system reliability; life expectancy; operational efficiency and optimal life-cycle costs. The criteria are expressed in general terms as have been detailed in the reference section noted. In use they are suitably developed and expanded to speak to different asset types, and include ways to convert subjective issues into quantitative to aid in producing comparable and repeatable results for project to project comparisons.

In the 2014 test year and going forward, Veridian has continued to use its CIP, but also introduced the ACA results into the management of its assets as the company develops a more formal Asset Management Plan (AMP). During the transition to its AMP, Veridian has begun to expanded its data gathering capabilities with improved access to electronic operating, maintenance and asset condition records to ensure that the cumulative condition and risk assessment of each asset category is available for decision-making. These changes have and will continue to steadily improve life-cycle management of assets, identify risk exposure, preventative maintenance and planned investment activities. The ACA will identify systemic problems such as wood pins in cross arms, porcelain insulators, etc., and include the acquisition or development of the appropriate risk management and assessment tools.

Facilities Asset Lifecycle Optimization

Due to Veridian's large and non-contiguous licensed service area, multiple facilities are maintained to support cost effective and timely service delivery to local communities. The majority of employees and business functions are accommodated at the corporate head office and main Operation Centre in Ajax. Satellite Operations Centres are located in Belleville, Gravenhurst, Clarington and Beaverton.

The following table summarizes the locations and related business functions carried out at each of Veridian's facilities:

Table 4: Table of Veridian Business Facilities

Location	Function(s)	Ownership Status
55 Taunton Road East Ajax	Corporate Head Office Main Operations Centre Main Warehouse	Owned – built in 1992 and expanded in 2010
459 Sidney Street Belleville	Office Staff Local Operations Centre Local Warehouse	Leased
195 Progress Avenue Gravenhurst	Office Staff Local Operations Centre Local Warehouse	Owned – built in 1994
2849 Hwy #2 Clarington	Local Operations Centre Local Warehouse	Owned – built in 1984
Hwy 12 Beaverton	Local Operations Centre	Owned – built in 1962

Location	Function(s)	Ownership Status
Township of Brock	Local Warehouse	

Preventive Maintenance, Inspections and Repairs

The Facilities Department conducts regular equipment maintenance to prevent equipment breakdown and to preserve and extend the useful life of facilities assets. Preventive measures include inspections, testing, lubrications, cleaning, and filter changes. Following are the key facilities components that are inspected and maintained on a monthly basis:

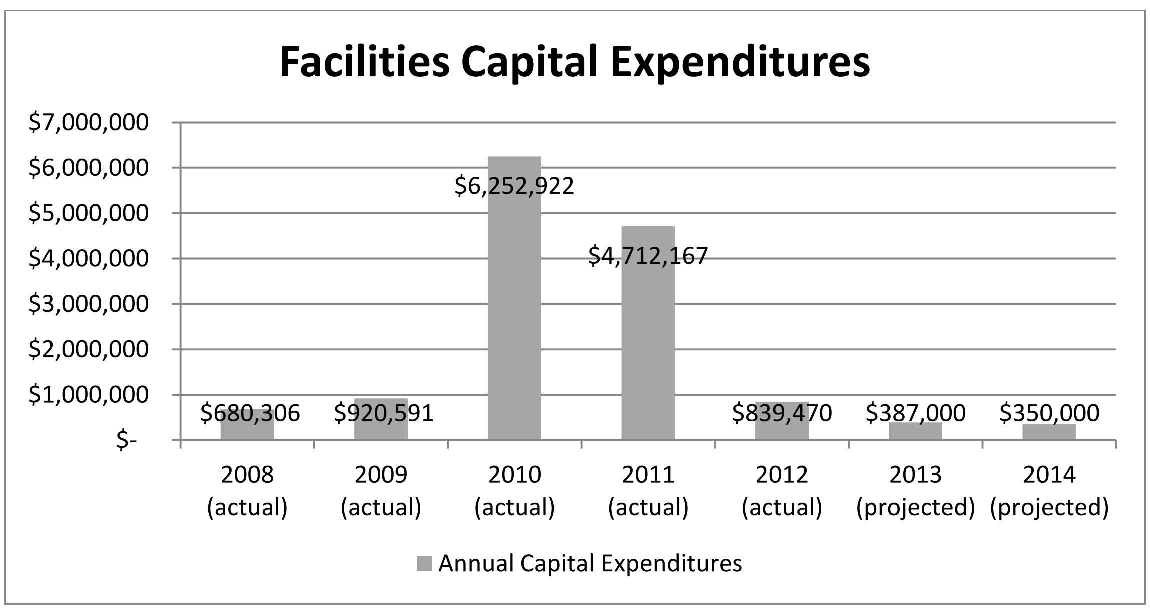
- Heating Ventilation and Air Conditioning ("HVAC") System
- Generator Equipment
- Water Management Systems
- Fire Systems
- Security Systems
- Yard Gates
- Lifting Devices (Fork Lifts, Elevator)

Veridian completes most minor repairs using internal resources. If a project requires specialized skills/equipment or is too large for Veridian's maintenance staff, contract resources are retained.

Facilities Capital Investments

In 2010 and 2011, non-recurring investments in the expansion and reconfiguration of the Ajax facility were made to consolidate business operations and to accommodate the space requirements of the System Control Centre. Details of these investments are provided at Exhibit 2, Tab 1, Schedule 2, Attachment 2. With the completion of this work, capital investment levels will largely be driven by asset sustainment and end-of-life replacement needs. This is reflected in table 2, which shows actual facilities capital spending for 2008 to 2012, and projections for 2013 and 2014.

Table 5: Facilities Capital Spending



The need for asset sustainment or end-of-life replacement investments is determined by the Facilities Department through regular condition assessments. The focus of the department is to provide sustained performance at the lowest life cycle cost to the organization.

Table 6 summarizes major facilities components, their typical life cycles, and the general guidelines used to determine the nature of asset sustainment investments related to each component.

Table 6: Building Systems & Equipment Sustainment Strategy

Asset	Typical Life Cycle	Replace / Refurbish Guideline	Comment
Furniture	10 years	Replace when damaged	Standardization of furniture across all locations addresses the following criteria: aesthetics, durability, maintenance, sustainability and warranty
HVAC Systems	25 years	Refurbish/Replace	Many system components can be refurbished to extend the life cycle
Generator Systems	25 years	Refurbish/Replace	Existing generators are in the early stage of their life cycle
Security System	15 years	Replace	System upgrade in 2013/2014
Fire Systems	20 years	Refurbish	Many system components can be refurbished to extend the life cycle

Asset	Typical Life Cycle	Replace / Refurbish Guideline	Comment
Roof Structures	20-30 years	Replace	Replace upon end of life
Parking Lot, Driveways	20 years	Replace	Replace upon end of life

The Facilities Department also continually seeks opportunities for investments in facilities energy efficiency related to lighting and HVAC systems. Energy efficiency retrofit opportunities are pursued if supported by a business case with a positive net present value.

Fleet Asset Lifecycle Optimization

Veridian owns and operates a fleet of vehicles currently numbering 127, as detailed in Table 7 below. Vehicles are deployed at each of the Operations Centres that support Veridian's business operations, which are located in Ajax, Clarington, Belleville, Beaverton and Gravenhurst. Vehicles are redeployed from one Operations Centre to another as required to optimize utilization and to meet current business needs.

Table 7: Fleet Composition

Category	Quantity	Average Age (years)
Vehicles, Large	29	9.6
Vehicles, Light (Passenger and service)	63	4.8
Trailers	29	13.4
Special Purpose *	6	6.3

*ATVs, snowmobiles and a boat

<u>Preventive Maintenance, Inspections and Repairs</u>

The fleet is centrally managed by staff located at Veridian's Ajax facility, which includes a two bay service garage. It is also equipped with a mobile repair unit to support vehicles deployed at work sites and district Operations Centres. Most repair and maintenance work is carried out by internal resources. Specialty repairs such as those related to body work and windshield replacements is outsourced to local repair shops.

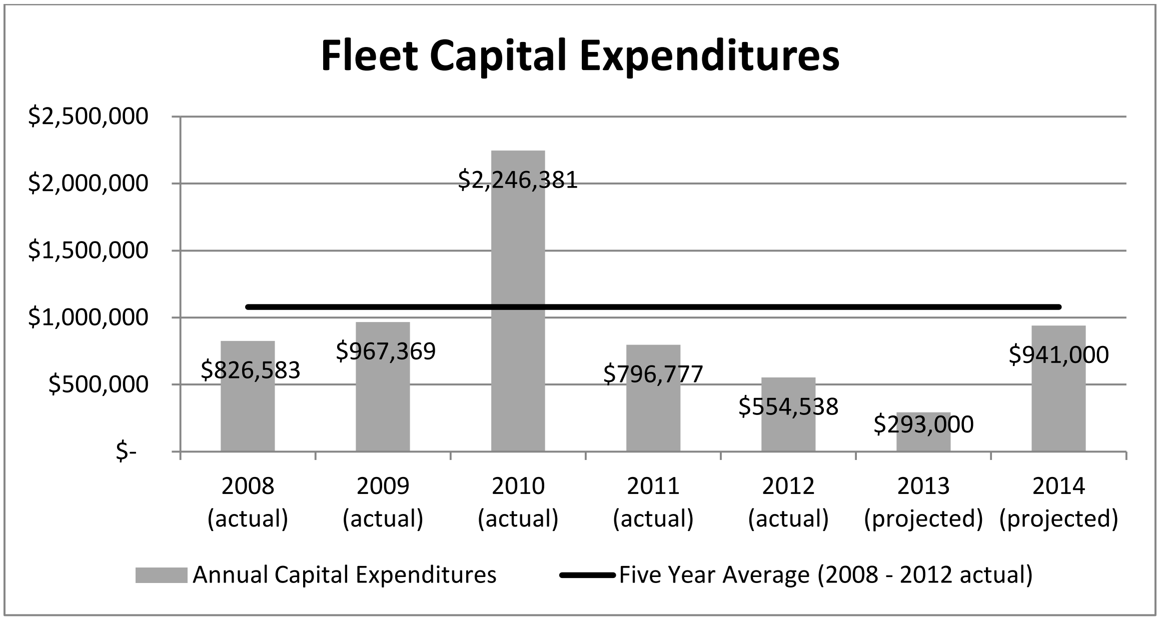
A fleet management software application is used to schedule preventive maintenance and inspection work, and to log all maintenance and repair activity. Preventive maintenance and inspections are carried out in accordance with vehicle manufacturer guidelines and all general and industry specific requirements such as those prescribed by:

- Transport Canada Motor Vehicle Safety Regulations
- Ontario's Highway Traffic Act
- Ontario's Drive Clean program
- Infrastructure Health & Safety Association

<u>Fleet Capital Investments</u>

The maintenance of a reliable fleet of vehicles is essential to the efficiency and productivity of Veridian's workforce. Sizable annual capital investments are required to sustain the fleet, as detailed in table 8 below. As shown, annual capital investment needs have averaged at just over $1 million based on the most recent five years of actual historical data.

Table 8: Fleet Capital Spending



While efforts are made to smooth the pace of annual expenditures, the end-of-life replacement of large fleet vehicles can result in lumpy investments, as occurred in 2010. Details regarding large vehicle replacements in that year were provided as part of Veridian's 2010 cost of service rate application, and are also discussed in Exhibit 2.

Investment decisions related to fleet vehicles are informed by a Fleet Committee, which includes vehicle users, a lead mechanic and a number of management representatives. The committee meets regularly to review vehicle utilization / functionality and work site deployments. It also conducts an annual review of the fleet to determine needs for refurbishments, replacements and additions. This review forms the basis for annual fleet capital budgets.

When conducting its annual review, the Fleet Committee utilizes the vehicle assessment guidelines shown in table 9 to identify candidate vehicles that may potentially require refurbishment or replacement investments. Candidate vehicles are then further assessed to determine if usage patterns confirm a continued need for the vehicle and, if so, whether it should be refurbished or replaced.

Table 9: Vehicle Assessment Guidelines

Vehicle Category		Threshold for Replacement or Refurbishment Assessment	
		Age (years)	**Mileage (km's)**
Vehicles, Large		>10	200,000
Vehicles, Light	Cars	> 4	150,000
	Vans & Pickup Trucks	> 5	150,000
Trailers		>12	n/a
Special Purpose		>15	n/a

The option of vehicle refurbishment is given close scrutiny for large vehicles such as bucket trucks and digger/derricks, due to the high cost of replacement. Typically a major overhaul of hydraulic and mechanical systems can cost effectively extend the vehicle life by three to five years. Veridian made extensive use of the vehicle refurbishment option over the past few years.

Fleet vehicle assets are acquired through a competitive process in accordance with Veridian's purchasing policy.

Fleet Asset Optimization Measures

In addition to the maintenance and capital investment planning processes described earlier in this exhibit, Veridian has adopted a number of technologies and practices to optimize the availability, reliability and use of its fleet assets. For example:

- Where possible, vehicles are rotated between work locations to optimize the combination of age and vehicle use that ultimately leads to a potential need for capital investments.
- Most fleet vehicles are equipped with Global Positioning System (GPS) equipment. Vehicle use information collected by this equipment is used for a range of asset management purposes such as remote vehicle diagnosis and collection of usage information for the purposes of usage audits and scheduling of preventive maintenance. It also serves as a theft deterrent, and has been used to recover stolen vehicles.
- A computerized fleet and fuel management system has been implemented to help monitor, evaluate and manage fuel usage.

Information Technology Asset Lifecycle Optimization

Assets managed through the Information Technology group include:

- Servers;
- Personal Computers;
- Printers;
- Network Infrastructure;
- Phone System;
- Various applications and
- Various UPS (uninterruptable power supply)

Technology lifecycle management encompasses:

- Assessment & Identification
- Technology Acquisition
- Support Services
- Technology Refresh
- Asset Disposal

The hardware replacement schedule is driven by time and performance. The typical replacement schedule is:

Category	**Time frame (years)**
Servers and Storage	5
Network Equipment	5
PC Desktops	4
VDI Desktops (Virtual Desktop Infrastructure)	5
Laptops	3

Software replacement is generally strategy driven rather than time driven.

In order to create an accurate picture of where IT infrastructure may evolve a Strategic and Operational Plan were developed.

Ensuring the viability, relevancy and long term value of the IT infrastructure also requires proper financial management. Addressing capital requirements over a period of time helps to reduce risk, lower total cost of ownership and leverage existing and future year's operations budgets.

Investments identified with in the plan are evaluated using the following criteria:

1. Strategic Alignment
    - How well does the IT investment align with the long-term goals of Veridian

2. Business Process Impact
    - How much would the initiative force changes to existing business processes

3. Technical Architecture
   - How scalable, resilient and simple to integrate with existing technologies are the databases, operating systems, applications and networks that would be implemented

4. Direct Payback
   - What benefits do the projects have in terms of cost savings, access to increased information or other advantages

   - Financial benefits will be evaluated using standard model developed by finance based on cash flows, NPV, IRR

5. Risk
   - How likely is it that the initiative will fail to meet expectations, and what costs are involved

Major applications that Veridian procures tend to be modular and expandable. This aids in extending the useful life of the asset.

Asset Lifecycle Risk Management Policies and Practices

Information Technology risk management is a component of the wider enterprise risk management process.

Veridian's IT policy with respect to risk management has and will focus on the following:

- Risk Assessment
- Risk Identification
- Risk Estimation
- Risk Evaluation
- Risk Mitigation
- Risk Communication
- Risk Monitoring and Review

To date the majority of Veridian's efforts have focused on the risk associated with security breaches and a catastrophic event that rendered existing facilities inoperable.

Steps have been taken to:

- Develop an IT Security Policy
- Test of the security of the AMI system
- In conjunction with a third party test the security of the smart meter
- Make recommendation to the meter manufacturer on security and functional improvements within the AMI
- Segregate servers and take steps to increase protection
- Train staff

- The development of a Business Continuity/Disaster Recovery Plan which identified key risks and determined a plan for IT applications and networks with respect to business continuity and disaster recovery

Attachment 1 of 1

Asset Condition Assessment

VERIDIAN

KINECTRICS

VERIDIAN CONNECTIONS
2013 ASSET CONDITION ASSESSMENT

September 27, 2013

Kinectrics Inc.
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VERIDIAN CONNECTIONS
2013 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418404-RA-0001-R01

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Revision History

Revision Number	Date	Comments	Approved
R00	June 3, 2013	Preliminary	Yury Tsimberg
R01	September 16, 2013	Draft	
	September 27, 2013	Final	

EXECUTIVE SUMMARY

Veridian Connections Inc (VC) determined a need to perform a condition assessment of its key distribution assets. Such an undertaking would result in a quantifiable evaluation of asset condition, aid in prioritizing and allocating sustainment resources, as well as facilitate further development of their Asset Management Plan.

In late 2012, VC selected and engaged Kinectrics Inc (Kinectrics) to perform an Asset Condition Assessment (ACA) on VC's key distribution assets.

The assets were divided into the following asset categories:

- Substation Transformers
- Substation Breakers
- Wood Poles
- Pole Mounted Transformers
- Overhead Line Switches
- Pad Mounted Transformers
- Vault Transformers
- Submersible Transformers
- Pad Mounted Switchgear
- Underground Cables

For each asset category, the ACA included the following tasks:

- Gathering relevant condition data
- Developing a Health Index Formula
- Calculating the Health Index for each asset
- Determining the Health Index distribution
- Developing a 20-year Flagged-For-Action Plan
- Identifying and prioritizing the data gaps for each group

This Asset Condition Assessment Report summarizes the methodology used, outlines specific approaches used in this project, and presents the resulting findings and recommendations.

Asset Condition Assessment Methodology

The Asset Condition Assessment Methodology involves the process of determining asset Health Index, as well as developing a Condition-Based Flagged-For-Action Plan for each asset category.

Health Index

Health Indexing quantifies equipment condition based on numerous condition parameters related to the long-term degradation factors that cumulatively lead to an asset's end of life. The

Health Index is an indicator of the asset's overall health, relative to a brand new asset, and is given in terms of percentage, with 100% representing an asset in brand new condition.

The condition data used in this study were obtained from VC and included the following:

- Asset Properties (e.g. age, asset type, location information)
- Test Results (e.g. Oil Quality, DGA)
- VC database, e.g. asset management

In order to provide an effective overview of the condition of each asset group, the Health Index Distribution for each asset category was determined.

Flagged-For-Action Plan

Once the Health Indices were calculated, a Flagged-For-Action Plan based on asset condition was developed. The Condition-Based Flagged-For-Action Plan outlines the number of units that are expected to be replaced in the next 20 years. The numbers of units were estimated using either a *reactive* or *proactive* approach.

For assets with a relatively small consequence of failure, units are generally replaced *reactively* or on failure. The Flagged-For-Action Plan for such an approach is based on the asset group's failure rate. This approach incorporates the possibility that assets may fail prematurely, prior to their expected typical end of lives.

In the *proactive* approach, units are assumed not to fail and are considered for replacement prior to failure. For asset groups that fall under this approach, a Risk Assessment study was conducted to determine the units eligible for replacement. This process establishes a relationship between asset Health Index and the corresponding probability of failure. Also involved was the quantification of asset criticality through the assignment of weights and scores to factors that impact the decision for replacement. The combination of criticality and probability of failure determines risk and replacement priority for that unit.

For some asset groups VC uses a mixed proactive/reactive approach depending on specific circumstances, e.g. some units are replaced when they fail and some could be replaced based on the test or visual inspection results before they fail. In the latter scenario, some action is sometimes taken, e.g. pole repairs or injection for the underground cables, to defer actual replacement.

Health Index Results

Table 1 shows a summary of the Health Index evaluation results. The Health Index distribution and percentage of the population in poor and very poor condition are shown. As well, the average age of each asset category is given.

Table 1 Health Index Results Summary

Asset Category	Population	Sample Size	Health Index Distribution (Units)					Total in Poor and Very Poor	Average Health Index	Average Data Availability Indicator	Average Age
			Very Poor (< 25%)	Poor (30 - < 50%)	Fair (50 - < 70%)	Good (70 - < 85%)	Very Good (>= 85%)				
Substation Transformers	79	75	9	7	12	10	37	16	62%	50.2%	29
Substation Breakers	141	129	1	6	10	6	106	7	72%	57.2%	28
Wood Poles	28000	1538	0	28	145	257	1108	28	87%	98.0%	28
Pole Mounted Transformers	7661	3754	41	65	108	219	3321	106	94%	19.0%	24
Overhead Line Switches	1968	646	126	99	118	9	294	225	66%	14.3%	9
Pad Mounted Transformers	8722	8143	102	32	467	258	7284	134	94%	67.1%	20
Vault Transformers	10	7	0	0	1	0	6	0	82%	28.0%	7
Submersible Transformers	24	24	0	0	0	0	24	0	99%	40.0%	15
Pad Mounted Switchgear	221	217	9	9	14	20	165	18	83%	24.9%	16
Underground Cables*	1595	1470	42	160	288	434	546	202	76%	92.2%	20
* cable length, in km											

A graphical representation of the Health Index results is shown in Figure 1.

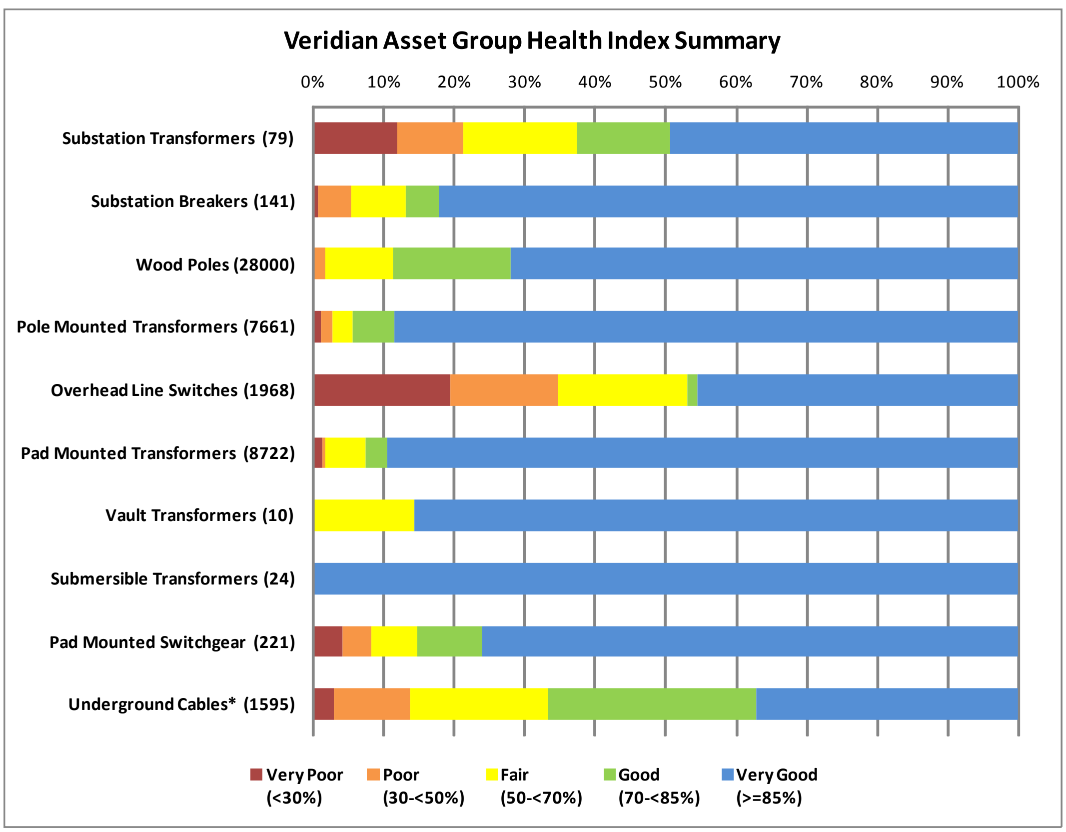

Figure 1 Visual Summary of Health Index Results

Condition Based Flagged-For-Action Plan

Table 2 shows the condition-based Flagged-For-Action Plan for the first year and the typical type of asset replacement strategy is shown for each asset group.

VC's most significant expected replacements in terms of the number of units were found to be for wood poles, pole mounted transformers, pad mounted transformers, overhead line switches and underground cables. The substation transformer, substation breaker and overhead line switch categories have a higher backlog flagged for action in the current year and it is expected that some of the units identified in the backlog will actually start to be replaced over the next few years thus reducing the initial spike in replacement costs.

Table 2 Year 1 Condition-Based Flagged-For-Action Plan

Asset Category	Condition-Based Flagged-For-Action Plan for Year 1 [Number of Units]	Flagged-for-Action Percentage for Year 1	Typical Replacement Strategy
Substation Transformers	13	16%	Proactive
Substation Breakers	6	4%	Proactive
Wood Poles	528	2%	Proactive/Reactive
Pole Mounted Transformers	116	2%	Reactive
Overhead Line Switches	299	15%	Reactive
Pad Mounted Transformers	206	2%	Reactive
Vault Transformers	0	0%	Reactive
Submersible Transformers	0	0%	Reactive
Pad Mounted Switchgear	8	4%	Proactive/Reactive
Underground Cables*	78	5%	Proactive/Reactive
* cable length, in km			

Data Assessment Results

Sufficient information and data were available for ACA study for the substation transformer, substation circuit breaker and pad mounted transformer asset categories.

For substation transformers, VC had collected sufficient dissolved gas analysis (DGA) data in the past years. However due to an issue with extraction of these data from DGA lab supplier databases, DGA results for only the last 2 years were available for this ACA study which was not sufficient for the trending analysis. It is expected that more of the previous years DGA results will be provided for the 2014 ACA study.

For 7 out of 10 asset groups, age information was available for the entire population. Wood poles, pole mounted transformers and overhead line switches may not have age information available for most of their populations. These have been identified as data gaps that require additional information.

In this ACA study, sufficient information and data were only available for the small sample of wood poles population. However, since the sample size was very small compared to the entire population, this means most of wood poles did not have the required condition data. Wood poles are a very important asset category representing a large portion of VC's assets book value and, as such, having a significant impact on future capital replacement needs. Therefore, it is recommended to close this gap in as expedient manner as possible.
For pad mounted switchgear, the inspection maintenance records were available for only part of the population.

Underground cables had age, cable type and installation method as the available information, plus some failure statistics data.

All the other asset groups lacked maintenance and operation information so their ACA studies were mainly age driven.

Conclusions and Recommendations

1. Of the asset categories assessed, substation breakers, pole mounted transformers, pad mounted transformers, vault transformers, submersible transformers were found generally to be in good condition.

2. Of the asset categories assessed, only the substation asset groups (substation transformers, substation circuit breakers) and pad mounted transformers had sufficient data and information for yielding a more reliable ACA results.

3. It was found that 16 Substation Transformers were in poor or very poor condition, out of which 13 units were flagged for action in the first year. This includes 5 spare units that were over 40 years old. For the "in-service" units, the major contributing factor is overall HI de-rating due to design issues of rectangular windings causing multiple failures at close-in faults. It is recommended that investments be made in an expedient manner to address this issue.

4. It is recommended that additional historical records of DGA readings, which were missing from this report, be incorporated in the ACA study for the next update in 2014, so as to facilitate DGA trending analysis.

5. The health index results show wood poles and overhead line switches in good and bad condition, respectively. However, in both cases the results were extrapolated based on a very small sample sizes. The sample sizes for each of these asset categories need to be significantly increased to validate results for the whole population.

6. For underground cables, the cables installed in direct buried duct show in much better condition than direct buried cables.

7. Other asset groups either had little information rather than age, or had the required information available only to a small part of population, thus making their ACA study mainly driven by age.

8. It is recommended that inspection be recorded in VC's asset management database even if no defect is found during routine inspection. This will facilitate the asset condition assessment in the future.

9. It is important to note that the Flagged-For-Action Plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence VC's asset management plan.

10. The Flagged-for-Replacement plan identify significant number of VC's assets **typically** run to failure and thus replaced *reactively*, such as pole mounted and pad mounted transformers and overhead line switches expected to fail over the next few years. It is recommended that a program be put in place to start *proactively* replacing some of the units in these asset categories in order to better manage the associated annual replacement cost.

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I INTRODUCTION

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I Introduction

Veridian Connections Inc (VC) is a local distribution company that distributes electricity to over 115,000 residential and commercial customers in the Cities of Pickering and Belleville, the towns of Ajax, Port Hope and Gravenhurst, and the communities of Uxbridge, Bowmanville, Newcastle, Orono, Port Perry, Beaverton, Sunderland and Cannington.

Veridian Connections Inc is a wholly owned subsidiary of Veridian Corporation. The City of Pickering, the Town of Ajax, the Municipality of Clarington and the City of Belleville jointly own Veridian Corporation. Activities, performance standards, and rates are regulated by the Ontario Energy Board.

Kinectrics Inc. (Kinectrics) is an independent consulting engineering company with the advantage of 90 years of expertise gained as part of one of North America's largest integrated electric power companies. Kinectrics has a depth of experience in the area of transmission and distribution systems and has become a prime source of Asset Management and Asset Condition services to some of the largest power utilities in North America.

In the summer of 2012, VC selected and engaged Kinectrics Inc (Kinectrics) to perform an Asset Condition Assessment (ACA) on VC's key distribution assets.

The Asset Condition Assessment Report summarizes the methodology, demonstrates specific approaches used in this project, and presents the resultant findings and recommendations.

I.1 Objective and Scope of Work

The assets in this study are categorized as follows:

- Substation Transformers
- Substation Breakers
- Wood Poles
- Pole Mounted Transformers
- Overhead Line Switches
- Pad Mounted Transformers
- Vault Transformers
- Submersible Transformers
- Pad Mounted Switchgear
- Underground Cables

For each asset category, the ACA included the following tasks:

- Gathering relevant condition data
- Developing a Health Index Formula
- Calculating the Health Index for each asset
- Determining the Health Index distribution
- Developing a 20-year risk-based/condition-based flagged-for-action plan
- Identifying and prioritizing the data gaps for each group

I.2 **Deliverables**

The deliverable in this study is a Report that includes the following information:

- Description of methodology for condition assessment of Flagged-For-Action Plan (Section II)
- Description of the data assessment procedure (Section III)
- For each asset category the following are included (VI Appendix A: Results and Findings for Each Asset Category: Section 1 – Section 10):
    - Short description of the asset groups and a discussion of asset degradation and end-of-life issues
    - Age distribution
    - Health Index formulation
    - Health Index distribution
    - Condition-based Flagged-For-Action Plan
    - Assessment of data availability by means of a Data Availability Indicator (DAI) and a Data Gap analysis

II ASSET CONDITION ASSESSMENT METHODOLOGY

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II Asset Condition Assessment Methodology

The Asset Condition Assessment (ACA) Methodology involves the process of determining asset Health Index, as well as developing a Condition-Based Flagged-For-Action Plan for each asset group. The methods used are described in the subsequent sections.

II.1 Health Index

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a parameter called "Oil Quality" may be a composite of parameters such as "Moisture", "Acid", "Interfacial Tension", "Dielectric Strength" and "Colour".

In formulating a Health Index, condition parameters are ranked, through the assignment of *weights*, based on their contribution to asset degradation. The *condition parameter score* for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

Health Index (HI), which is a function of scores and weightings, is therefore given by:

$$HI = \frac{\sum_{m=1}^{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{\forall m} \alpha_m (CPS_{m.\max} \times WCP_m)} \times \frac{1}{CPF_{\max}} \times DR$$

Equation 1

where

$$CPS = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{n=1}^{\forall n} \beta_n (CPF_{\max} \times WCPF_n)}$$

Equation 2

CPS	Condition Parameter Score
WCP	Weight of Condition Parameter
α_m	Data availability coefficient for condition parameter
CPF	Sub-Condition Parameter Score
WCPF	Weight of Sub-Condition Parameter
β_n	Data availability coefficient for sub-condition parameter
DR	De-Rating Multiplier

The scale that is used to determine an asset's score for a particular parameter is called the *condition criteria*. For this project, a condition criteria scoring system of 0 through 4 is used. A score of 0 represents the worst score while 4 represents the best score. I.e. $CPF_{max} = 4$.

II.1.1 Health Index Example

Consider the asset class "Oil Circuit Breaker". The condition and sub-condition parameters, as well as their weights are shown on Table II-3.

Table II-1 Oil Circuit Breaker Condition and Sub-Condition Parameters

Health Index Formula for Oil Circuit Breakers			
Condition Parameters		**Sub-Condition Parameters**	
Name	**Weights (WCP)**	**Name**	**Weights (WCPF)**
Operating Mechanism	14	Lubrication	9
		Linkage	5
		Cabinet	2
Contact Performance	7	Closing Time	1
		Trip Time	3
		Contact Resistance	1
		Arcing Contact	1
Arc Extinction	9	Moisture	8
		Leakage	1
		Tank	2
		Oil Level	1
		Oil Quality	8
Insulation	2	Insulation	1
Service Record	5	Operating Counter	2
		Loading	2
		Age	1

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. The maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is therefore "4".

Scores are determined using *condition criteria*. The criterion defines the score of a particular parameter. Consider, for example, the age criteria given on Table II-4. An asset that is 35 years old will receive a score of "2" for "Age".

Table II-2 Age Criteria

Parameter Score	Condition Description
4	0-19
3	20-29
2	30-39
1	40-44
0	45+

Table II-5 shows a sample Health Index evaluation for a particular oil breaker. The sub-condition parameter scores (CPFs) shown are assumed values between 0 through 4.

The Condition Parameter Score (CPS) is evaluated as per Equation 2. The Health Index (HI) is calculated as per Equation 1. As no de-rating factors are defined, there is no multiplier for the final Health Index.

Table II-3 Sample Health Index Calculation

Condition Parameters	Operating Mechanism			Contact Performance			Arc Extinction			Insulation			Service Record		
Sub-Condition Parameters Scores (CPF) Weights (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)	Sub-Condition Parameter	CPF	Weight (WCPF)
	Lubrication	4	9	Closing Time	2	1	Moisture	4	8	Insulation	4	1	Operating Counter	3	2
	Linkage	2	5	Trip Time	3	3	Leakage	3	1				Loading	4	2
	Cabinet	3	2	Contact Resistance	2	1	Tank	3	2				Age	3	1
				Arcing Contact	3	1	Oil Level	2	1						
							Oil Quality	3	8						
Condition Parameter Score (CPS)	Operating Mechanism CPS (4*9 + 2*5 + 3*2) / (9+5+2) = 3.25			Contact Performance CPS (2*1 + 3*3 + 2*1 + 3*1) / (1+3+1+1) = 2.67			Arc Extinction CPS (4*8 + 3*1 + 3*2 + 2*1 + 3*8) / (8+1+2+1+8) = 3.35			Insulation CPS (4*1) / (1) = 4			Service Record CPS (3*2 + 4*2 + 3*1) / (2+2+1) = 3.4		
Weights (WCP)	*Weight = 14*			*Weight = 7*			*Weight =9*			*Weight = 2*			*Weight = 5*		
Health Index (HI)	$HI = \frac{3.25*14 + 2.67*7 + 3.35*9 + 4*2 + 3.4*5}{(14 + 7 + 9 + 2 + 5)*4} =$ **80.6%**														

II.1.2 Health Index Results

As stated previously, an asset's Health Index is given as a percentage, with 100% representing "as new" condition. The Health Index is calculated only if there is sufficient condition data. The subset of the population with sufficient data is called the *sample size*. Results are generally presented in terms of number of units and as a percentage of the sample size. If the sample size is sufficiently large and the units within the sample size are sufficiently random, the results may be extrapolated for the entire population.

The Health Index distribution given for each asset group illustrates the overall condition of the asset group. Further, the results are aggregated into five categories and the categorized distribution for each asset group is given. The Health Index categories are as follows:

Very Poor	Health Index < 25%
Poor	25 ≤ Health Index < 50%
Fair	50 ≤ Health Index <70%
Good	70 ≤ Health Index <85%
Very Good	Health Index ≥ 85%

Note that for critical asset groups, such as Station Transformers, the Health Index of each individual unit is given.

II.2 **Condition-Based Flagged-for-Action Methodology**

The Condition-Based Flagged-For-Action Plan outlines the number of units that are projected to be replaced in the next 20 years. The numbers of units are estimated using either a *proactive, reactive,* or mixed *proactive/reactive* approach. In the proactive approach, units are considered for replacement prior to failure. In both the reactive and mixed proactive/reactive approaches, replacement of units is based on expected failures per year.

All these approaches consider asset failure rate and probability of failure. The failure rate is estimated using the method described in the subsequent section.

II.2.1 Failure Rate and Probability of Failure

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides the best model. This is based on the Gompertz-Makeham law of mortality. The original form of the failure function is:

$$f = \gamma e^{\beta t}$$

Equation 3

f	= failure rate per unit time
t	= time
γ, β	= constant that control the shape of the curve

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' expertise in failure rate study of multiple power system asset groups, the following variation of the failure rate formula is adopted:

$$f(t) = e^{\beta(t-\alpha)}$$

Equation 4

f	= failure rate of an asset (percent of failure per unit time)
t	= age (years)
α, β	= constant parameters that control the rise of the curve

The corresponding probability of failure function is therefore:

$$P_f(t) = 1 - e^{-(f-e^{-\alpha\beta})/\beta}$$

Equation 5

P_f	= cumulative probability of failure

Different asset groups experience different failure rates and therefore different probabilities of failure. As such, the shapes of the failure and probability curves are different. The parameters α and β are used to control the location and steepness of the exponential rise of these curves. For each asset group, the values of these constant parameters were selected to reflect typical useful lives for these assets.

Consider, for example, an asset class where at the ages of 25 and 65 the asset has cumulative probabilities of failure of 10% and 99% respectively. It follows that when using Equation 5, α and β are calculated as 74 and 0.093 respectively. As such, for this asset class the cumulative probability of failure equation is:

$$P_f(t) = 1 - e^{-(e^{\beta(t-\alpha)}-e^{\alpha\beta})/\beta} \; = \; 1 - e^{-(e^{0.093(t-74)}-e^{-6.882})/0.093}$$

The failure rate and probability of failure graphs are as shown:

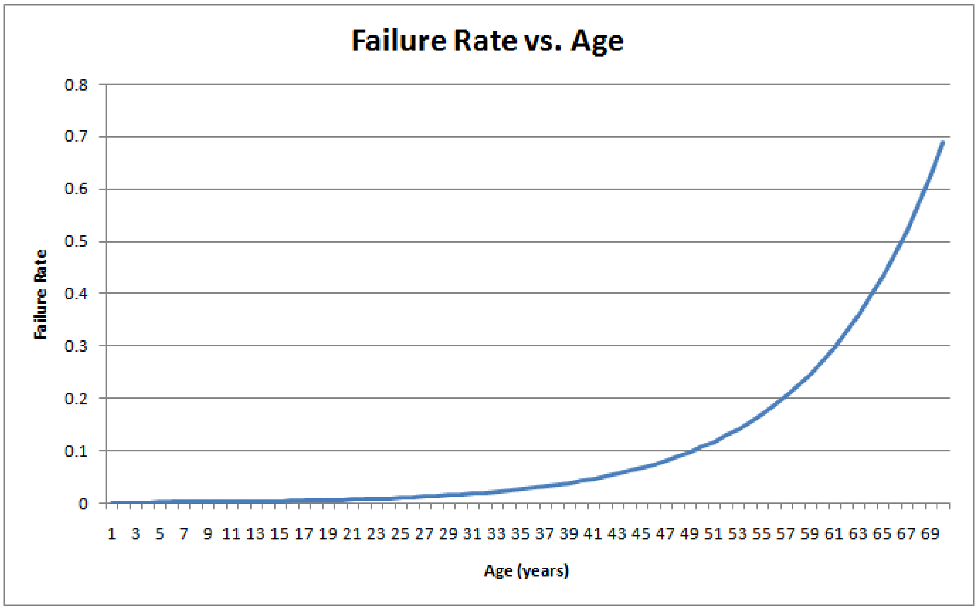

Figure II-1 Failure Rate vs. Age

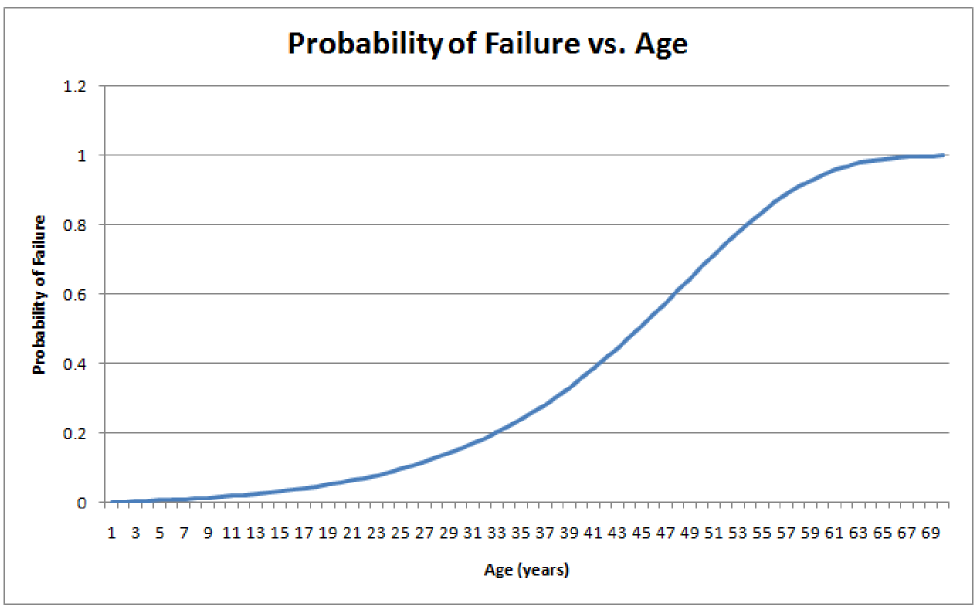

Figure II-2 Probability of Failure vs. Age

II.2.2 Projected Flagged-for-Action Plan in Proactive Approach

For certain asset classes, the consequence of asset failure is significant, and, as such, these assets are proactively replaced prior to failure. The proactive replacement methodology involves relating an asset's Health Index to its probability of failure by considering the stresses to which it is exposed.

Relating Health Index and Probability of Failure

Failure of an asset occurs when the stress to which an asset is exposed exceeds its strength. Assuming that stress is not constant, and that stress is normally distributed, the probability of stress exceeding asset strength leads to the probability of failure. This is illustrated in the figure below. A vertical line represents condition or strength (Health Index) and the area under the curve to the right of the Health Index line represents the probability of failure.

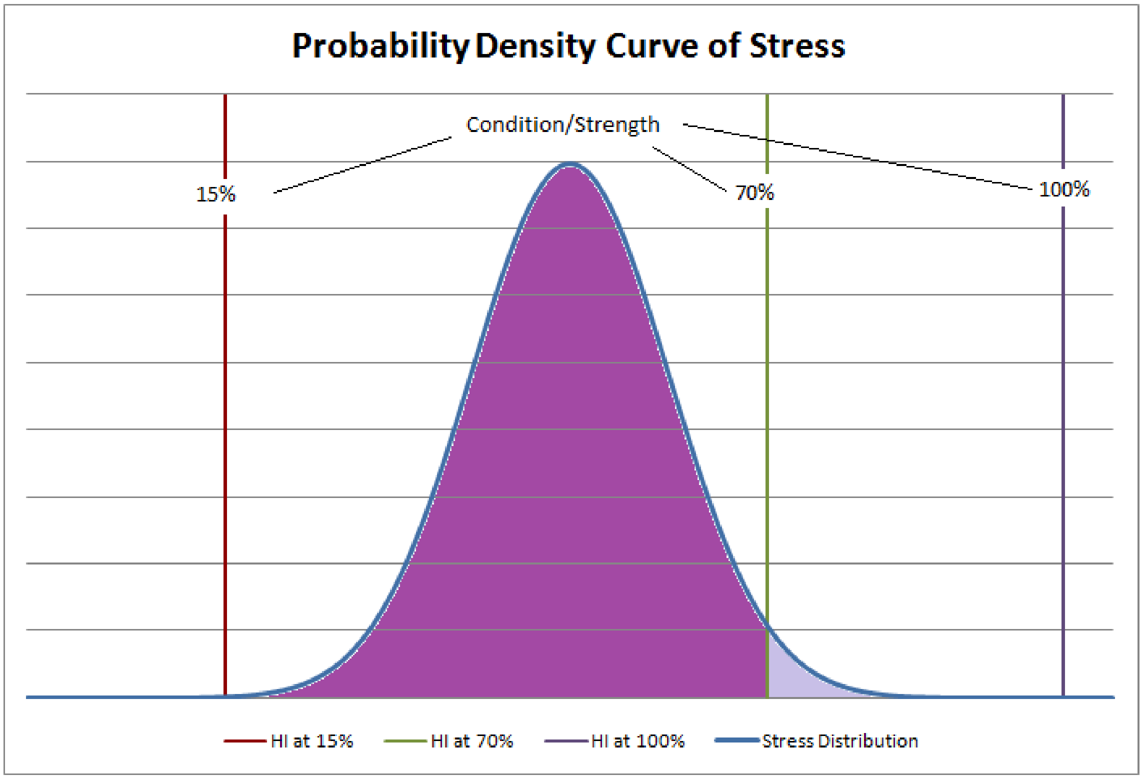

Figure II-3 Stress Curve

Two points of Health Index and probability of failure are needed to generate the probability of failure at other Health Index values. A Health Index of 100% represents an asset that is in brand new condition and a Health Index of 15% represents the asset's end of life. The 100% and 15% conditions are plotted on the stress curve by finding the points at which the areas under the stress curve are equal to $P_{f\ 100\%}$(age at 100% Health Index) and $P_{f\ 15\%} = P_f$(age at 15% Health Index). By moving the vertical line left from 100% to 15%, the probabilities of failure for other Health Indices can be found.

The probability of failure at a particular Health Index is found from plotting the Health Index on the X-axis and the area under the probability density curve to the right of the Health Index line on the Y-axis as shown on the graph of the figure below.

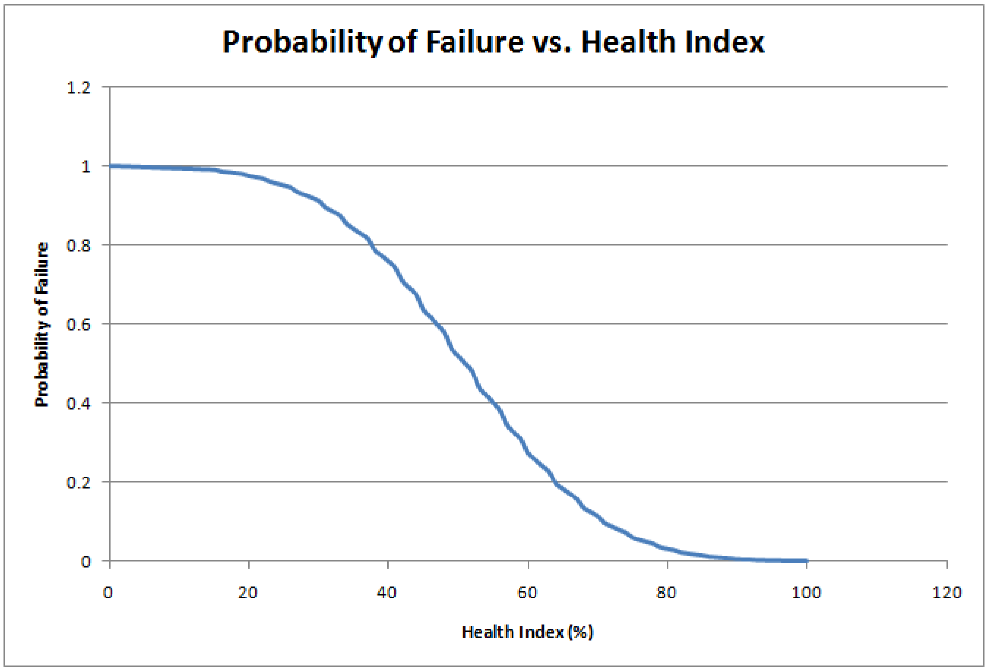

Figure II-4 Probability of Failure vs. Health Index

<u>Relating Health Index to Effective Age</u>

Once the relationship between probability of failure and Health Index has been found, the "effective age" of an asset can be determined. The "effective age" is different from chronological age in that it is based on the asset's condition and the stresses that are applied to the asset.

The probability of failure associated with a specific Health Index can be found using the Probability of Failure vs. Health Index (Figure II-4) and Probability of Failure vs. Age (Figure II-2). The probability of failure at a particular Health Index can be found from Figure II-4. The same probability of failure is located on Figure II-2, and the effective age is on the horizontal axis of Figure II-2. See example on the figure below where a Health Index of 60% corresponds to an effective age of 35 years.

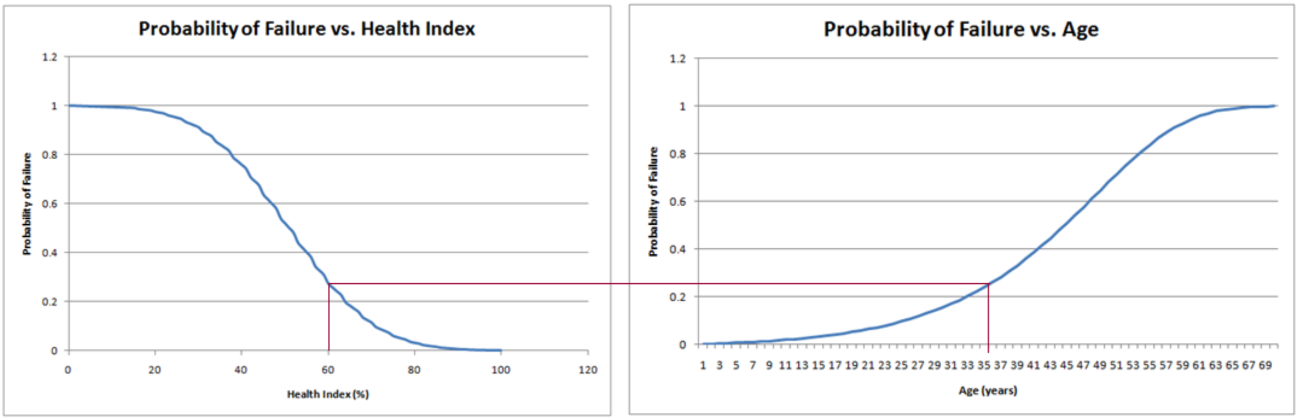

Figure II-5 Effective Age

Condition-Based Flagged-For-Action Plan

In order to develop a Flagged-For-Action Plan, the risk of failure of each unit must be quantified. Risk is the product of a unit's probability of failure and its consequence of failure.

The probability of failure is determined by an asset's Health Index. In this study, the metric used to measure consequence of failure is referred to as *criticality*.

Criticality may be determined in numerous ways, with monetary consequence or degree of risk to corporate business values being examples. For Substation Transformers, factors that impact criticality may include things like number of customers or location. The higher the criticality value assigned to a unit, the higher is it's consequence of failure.

It is assumed in this study that each asset group has a base criticality value, Criticality_{min}. The individual units in the asset group are assigned Criticalities that are multiples of Criticality_{min}. A unit becomes a candidate for replacement when its risk value, the product of its probability of failure and criticality, is greater than or equal to 1.

In the example shown below, Asset 1 and Asset 2 are candidates for replacement.

Table II-4 Sample Replacement Ranking

Asset Name	Age	Health Index (HI)	Consequence of Failure (Criticality)	Probability of Failure (POF) Corresponding to HI	Risk (POF*Criticality)	Replacement Ranking
Asset 1	41	30.00%	2	78.20%	1.564	1
Asset 2	29	30.00%	1.5	78.20%	1.173	2
Asset 3	37	30.00%	1	78.20%	0.782	3
Asset 4	42	50.00%	2	12.80%	0.256	4
Asset 5	18	50.00%	1.5	12.80%	0.192	5
Asset 6	20	50.00%	1	12.80%	0.128	6

II.2.3 Projected Flagged-For-Action Plan in Reactive Approach

Because their consequences of failure are relatively small, many types of distribution assets are reactively replaced.

For such asset types, the number of units expected to be replaced in a given year are determined based on the asset's failure rates. The number of failures per year is given by Equation 4 in II.2.1.

An example of such a Flagged-For-Action Plan is as follows: Consider an asset distribution of 100 - 5 year old units, 20 – 10 year old units, and 50 - 20 year old units. Assume that the failure rates for 5, 10, and 20 year old units for this asset class are f_5 = 0.02, f_{10} = 0.05, f_{20} = 0.1 failures / year respectively. In the current year, the total number of replacements is 100(.02) + 20(0.05) + 50(0.1) = 2 + 1 + 5 = 8.

In the following year, the expected asset distribution is, as a result, as follows: 8 – 1 year old units, 98 – 6 year old units, 19 – 11 year old units, and 45 - 21 year old units. The number of replacements in year 2 is therefore 8(f_1) + 19(f_6) + 45(f_{11})+ 45(f_{21}).

Note that in this study the "age" used is in fact "effective age", or condition-based age where available, as opposed to the chronological age of the asset.

II.2.4 Projected Flagged-For-Action Plan in Mixed Proactive/Reactive Approach

The flagged-for-action plan for the units maintained in mixed proactive/reactive approach is the same as the one adopted for reactively replaced units.

III DATA ASSESSMENT

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III Data Assessment

The condition data used in this study were obtained from VC and included the following:

- Asset Properties (e.g. age, PCB content, location information)
- Test Results (e.g. Oil Quality, DGA)
- Non-Conformance Logs

There are two components that assess the availability and quality of data used in this study: Data Availability Indicator (DAI) and Data Gap.

III.1 Data Availability Indicator (DAI)

The Data Availability Indicator (DAI) is a measure of the amount of condition parameter data that an asset has, as measured against the condition parameters included in the Health Index formula. It is determined by the ratio of the weighted condition parameters score and the subset of condition parameters data available for the asset over the "best" overall weighted, total condition parameters score. The formula is given by:

$$HI = \frac{\sum_{m=1}^{\forall m} (DAI_{CPS\,m} \times WCP_m)}{\sum_{m=1}^{\forall m} (WCP_m)}$$

Equation 6

where

$$DAI_{CPSm} = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_{n\max} \times WCFn)}{\sum_{n=1}^{\forall n} (CPF_{n.\max} \times WCPFn)}$$

Equation 7

DAI_{CPSm}	Data Availability Indicator for Condition Parameter m with n Condition Parameter Factors (CPF)
β_n	Data Availability Coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)
$WCPF_n$	Weight of Condition Parameter Factor n
DAI	Overall Data Availability Indicator for the m Condition Parameters
WCP_m	Weight of Condition Parameter m

For example, say an asset has condition parameters A, B, and C with weights of 1, 2, and 3 respectively. Condition parameter scores are rated from 0 through 4, so the maximum score is 4. The maximum product of score and weight is therefore given by (maximum score)*weight. Thus, for conditions A, B, and C, the maximum products are 4*1 = 4, 4*2 = 8, and 4*3 = 12 respectively. It follows that the sum of maximum products for all possible conditions = 4+8+12 = 24. If asset X only has data for conditions A and B, the sum of maximum product of available conditions = 4+8 = 12. Its DAI is therefore 12/24 = 50%.

An asset with all condition parameter data represented will, by definition, have a DAI value of 100%. In this case, an asset will have a DAI of 100% regardless of its Health Index score.

It is important to note that DAI is measured against the parameters make up the Health Index formula and that the Health Index formula is based only on data that is collected by VC. There are additional parameters are important indicators of degradation that may not be collected (discussed in Section III.2). An asset may have a high DAI but the quality of parameters used in the Health Index formula may need improvement. When the condition parameters used in the Health Index formula are of good quality with little data gaps and the DAI is high, there will be a high degree of confidence that the Health Index score accurately reflects the asset's condition.

III.2 **Data Gap**

The Health Index formulations developed and used in this study are based solely on VC's available data. There are additional parameters or tests that VC may not collect but nonetheless are important indicators of the deterioration and degradation of assets. The set of unavailable data are referred to as data gaps. I.e. A data gap is the case where none of the units in an asset group has data for a particular item. The situation where data is provided for only a sub-set of the population is not considered as a data gap.

As part of this study, the data gaps of each asset category are identified. In addition, the data items are ranked in terms of importance. There are three priority levels, the highest being most indicative of asset degradation.

Priority	Description	Symbol
High	Critical data; most useful as an indicator of asset degradation	✫✫✫
Medium	Important data; can indicate the need for corrective maintenance or increased monitoring	✫✫
Low	Helpful data; least indicative of asset deterioration	✫

It is generally recommended that data collection be initiated for the most critical items because such information will result in higher quality Health Index formulations.

The more critical and important data included in the Health Index formula of a certain asset group, and the higher the Data Availability Indicator of a particular unit in that group, the higher the confidence in the Health Index calculated for the particular unit.

If an asset group has significant data gaps and lacks good quality condition, there is less confidence that the Health Index score of a particular unit accurately reflects its condition, regardless of the value of its DAI.

To facilitate the incorporation of data gap items into improved Health Index formulas for future assessments, the data gaps items are presented in this report as sub-condition parameters. For each item, the parent condition parameter is identified. Also given are the object or component addressed by the parameter, a description of what to assess for each component or object, and the possible source of data.

The following is an example for "Tank Corrosion" on a Pad-Mounted Transformer:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Tank Corrosion	Physical Condition	☆☆	Oil Tank	Tank surface rust or deterioration due to environmental factors	Visual Inspection

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IV RESULTS

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IV Results

This section summarizes the findings of this study.

Health Index Results

A summary of the Health Index evaluation results is shown in Table IV-1. The population and sample size, or number of assets with sufficient data for Health Indexing, are given. For each group the Health Index Distribution, Percentage in Poor and Very Poor Condition, and average Health Index are shown. Also given are the average age of each group and the percentage of the population for which age is available.

It can be seen from the results that in general, substation breakers, pad mounted transformers, vault transformers and submersible transformers are the asset groups that are of less concern, as they have less than 5% of population in poor or very poor condition.

The health index results of wood poles show less than 5% of the sampled units are in poor or very poor condition. Due to lack of data for the rest of wood poles, such results are extrapolated to the entire population in this study. This is based on the assumption that the small sample size represents the condition status distribution of the entire population. However, such a hypothesis remains to be validated by additional information in the future.

Among the other asset groups, the main concern is on substation transformers, overhead line switches, and underground cables, as they all have nearly 20% or higher of population in poor or very poor condition.

Flagged-For-Action Plan

The condition-based Flagged-For-Action Plan for the first year and the asset replacement strategy is shown for each asset group in Table IV-2.

Table IV-3 shows the 20 year optimized Flagged-For-Action Plan.

It is important to note that the Flagged-For-Action Plan suggested in this study is based solely on asset condition. It uses a probabilistic, non-deterministic, approach and as such can only show expected failures or probable number of units for replacement. As such, Condition-Based Flagged-For-Action Plan can be used as a guide or input to VC's capital planning and other factors and considerations , such as obsolescence, municipal initiatives, distribution system growth, etc. are expected to influence VC's asset management decisions. Furthermore, the "actions" resulting from the Flagged-For-Action Plan for *proactively* or *proactively/reactively* replaced asset categories will consider actions other than replacement, such as refurbishment, more frequent inspections and/or monitoring or simply "do nothing".

VC's most significant expected replacements in current year were found to be for Substation Transformers. The units flagged for action in the current year comprise 16% of the entire population. Some other asset groups, such as substation breakers and overhead line switches, also have a higher backlog flagged for action in the current year. In all these cases, fewer or no further action is required in the years that follow.

In the near future, VC's most significant expected replacements in terms of unit were found to be for wood poles, pole mounted transformers, and pad mounted transformers, overhead line switches and underground cables.

Table IV-1 Health Index Results Summary

Asset Category	Population	Sample Size	Health Index Distribution (% of Sample Size)					Total in Poor and Very Poor	Average Health Index	Average Data Availability Indicator	Average Age
			Very Poor (< 25%)	Poor (30 - < 50%)	Fair (50 - < 70%)	Good (70 - < 85%)	Very Good (>= 85%)				
Substation Transformers	79	75	12.0%	9.3%	16.0%	13.3%	49.3%	21.3%	62%	50.2%	29
Substation Breakers	141	129	<1%	4.3%	7.1%	4.3%	75.2%	4.3%	72%	57.2%	28
Wood Poles	28000	1538	0.0%	1.8%	9.4%	16.7%	72.0%	1.8%	87%	98.0%	28
Pole Mounted Transformers	7661	3754	1.1%	1.7%	2.9%	5.8%	88.5%	2.8%	94%	19.0%	24
Overhead Line Switches	1968	646	19.5%	15.3%	18.3%	1.4%	45.5%	34.8%	66%	14.3%	9
Pad Mounted Transformers	8722	8143	1.2%	<1%	5.4%	3.0%	83.5%	1.2%	94%	67.1%	20
Vault Transformers	10	7	0.0%	0.0%	10.0%	0.0%	60.0%	0.0%	82%	28.0%	7
Submersible Transformers	24	24	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	99%	40.0%	15
Pad Mounted Switchgear	221	217	4.1%	4.1%	6.3%	9.0%	74.7%	8.1%	83%	24.9%	16
Underground Cables*	1595	1470	2.9%	10.9%	19.6%	29.5%	37.1%	13.8%	76%	92.2%	20

*** cable length, in km**

Table IV-2 Twenty Year Condition Based Flagged-For-Action Plan

Asset	Total Population	Flagged-for-Action Year																			
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Substation Transformers	79	13	2	0	1	0	0	0	1	1	0	2	1	0	2	1	2	1	1	0	1
Substation Breakers	141	6	0	0	1	0	0	0	0	0	0	0	0	1	1	2	0	0	0	0	0
Wood Poles	28000	528	583	619	674	710	765	801	837	874	910	928	947	965	983	983	983	965	947	947	910
Pole Mounted Transformers	7661	116	96	94	94	96	100	102	106	108	112	116	118	122	127	129	133	137	141	145	149
Overhead Line Switches	1968	299	238	186	137	101	76	58	46	40	37	37	40	46	49	52	52	55	58	61	67
Pad Mounted Transformers	8722	206	161	172	189	205	217	225	231	240	255	274	291	304	311	310	301	288	274	263	258
Vault Transformers	10	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
Submersible Transformers	24	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	2	2
Pad Mounted Switchgear	221	8	7	6	6	6	6	6	6	6	6	7	7	7	7	7	7	9	9	9	9
Underground Cables*	1595	78	78	78	77	76	74	71	68	64	59	54	48	42	36	29	24	19	16	15	15

*** cable length, in km**

Data Assessment Results

For 7 out of 10 asset groups, age information is available for the entire population. For the remaining 3 groups, namely wood poles, pole mounted transformers and overhead line switches, there are not enough age data due to the small sample sizes of these 3 groups.

Sufficient information and data were available for ACA study for the two asset groups inside substations (namely substation transformers and substation circuit breakers), as well as pad mounted transformers. Specifically for wood poles, although there was sufficient information and data for the sample units, there was no data available for the remaining 94% of the population. Given the very small sample size with reference to the entire population, this was a significant data shortfall.

For pad mounted switchgear, while the inspection maintenance records were recorded, they were available for only part of the population.

All other groups for distribution transformers and switches had their ACA study mainly driven by age. For future ACA study, their inspection maintenance records need to be stored in asset management even if no defect is found. Their condition assessment heavily relies on the historic trend of such records.

For substation transformers, VC has collected several years of DGA test results in the database. However, due to data extraction issue, in this study only last 2 readings of such DGA records were available, thus not providing information for trending analysis. It is expected that more of the previously collected DGA data will be used in 2014 ACA study to facilitate DGA trending analysis.

Vault transformers and submersible transformers have age as the only information.

Underground cables had age, cable type and installation method as the available information, plus some failure statistics data.

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V CONCLUSIONS AND RECOMMENDATIONS

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V Conclusions and Recommendations

1. An Asset Condition Assessment was conducted for ten of VC's key distribution asset categories. For each asset category, the Health Index distribution was determined and a condition-based Flagged-For-Action Plan was developed.

2. Of the asset categories assessed, substation breakers, pole mounted transformers, pad mounted transformers, vault transformers, submersible transformers were found generally to be in good shape, with over 80% of the population in "very good" condition.

3. Of the asset categories assessed, only the substation asset groups (substation transformers, substation circuit breakers), and pad mounted transformers have sufficient data and information for yielding reliable ACA results.

4. It was found that 16 of VC's Substation Transformers are in "poor" or "very poor" condition, 13 of which were flagged for action in the first year. This includes 11 transformers in service and 5 spare units. For the 5 spare units, the major contributing factor was their ages (over 40 years). For the 11 active transformers, the major contributing factor was the design issue of their rectangular winding, which led to multiple failures at close-in faults. Because this asset group is crucial distribution system components with major consequences of failure, it is recommended that investments be made in an expedient manner to address this issue.

5. While VC has collected years of DGA test data for all Substation Transformers, in this study only the last 2 readings of DGA tests records were available. This was due to a data extraction issue. It is recommended that the historical test records be provided for several years and be used in subsequent ACA projects to study the DGA variation trend.

6. The Health Index results for wood poles that were tested show they were in good shape. However, these results were only for a small sample size (about 6% of the total population) of predominantly 44 kV poles that are expected to be in a better condition than the wood poles of lower voltage feeders. Therefore, the extrapolated Health Index results in this study are likely better than the actual ones. Wood poles are a very important asset category representing a large portion of VC's assets book value and, as such, are expected to have a significant impact on future capital replacement needs. Therefore, it is recommended to close this gap in as expedient manner as possible in order to derive a more accurate Health Index distribution for this asset category.

7. The health index results for overhead line switches show more than one third of the population were in "poor" or "very poor" condition. However, these were extrapolated based on a small sample size (less than 33%). Whether such health index results represent the actual condition distribution of the entire population remains to be validated by additional information.

8. In the study it was found that the sample size was also too small for overhead line switches. This affected the accuracy of the health index results. It is recommended that information be collected for more units in this category.

9. For underground cables, the cables in duct are in a much better shape than direct buried ones so that the replacement/refurbishment focus should be on direct buries cables. It is recommended to initiate a proactive replacement/refurbishment program for this asset category in addition to replacement on failure to smooth out the expected bow wave of failure expected over the next several years.

10. Other asset groups either had little information rather than age, or had the required information available only to a small part of population, thus making their ACA study mainly driven by age.

11. It is recommended to standardize record and store information when replacing Poles, Vault/Submersible/Pad-Mounted Transformers, and Overhead Line Switches to include reasons for replacement and age at replacement.

12. It is important to note that the Flagged-For-Action Plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence VC's asset management plan.

13. The Flagged-for-Replacement plan identify significant number of VC's assets **<u>typically</u>** run to failure and thus replaced *reactively*, such as pole mounted and pad mounted transformers and overhead line switches expected to fail over the next few years. It is recommended that a program be put in place to start *proactively* replacing some of the units in these asset categories in order to better manage the associated annual replacement cost.

VI APPENDIX A: RESULTS AND FINDINGS FOR EACH ASSET CATEGORY

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1 Substation Transformers

While substation power transformers can be employed in either step-up or step-down mode, a majority of the applications in distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. For distribution stations, power transformer ratings typically range from 3 MVA to 30 MVA. The units included in this study range from 3 MVA to 10 MVA.

Power transformers employ many different design configurations, but they are typically made up of the following main components:

- Primary and secondary windings
- Laminated iron core
- Internal insulating mediums
- Main tank
- Bushings
- Cooling system, including radiators, fans (Optional)
- Off load tap changer (Optional)
- On load tap changer (Optional)
- Instrument transformers
- Control mechanism cabinets
- Instruments and gauges

The primary and secondary windings are installed on a laminated iron core and serve as the coils in which electromotive force is produced when alternating magnetic flux passing through the core links with the windings. The internal insulating mediums provide insulation for energized coils. Insulating oil serves as the insulating medium as well as serves as the coolant. Due to its low cost, high dielectric strength, excellent heat-transfer characteristics, and ability to recover after dielectric overstress, mineral oil is the most widely used transformer insulating material. The transformer coil insulation is reinforced with different forms of solid insulation that include wood-based paperboard (pressboard), wrapped paper and insulating tapes. Because the dielectric strength of oil is approximately half that of the pressboard, the dielectric stress in the oil ends up being higher than that in the pressboard, and the design structure is usually limited by the stress in the oil. The insulation on the conductors of the winding may be enamel or wrapped paper which is either wood or nylon based. The use of insulation directly on the conductor actually inhibits the formation of potentially harmful streamers in the oil, thereby increasing the strength of the structure. Heavy paper wrapping is also usually used on the leads coming from the windings.

The main tank holds the active components of the transformer in an oil volume and maintains a sealed environment through the normal variations of temperature and pressure. Typically, the main tank is designed to withstand a full vacuum for initial and subsequent oil fillings and is able to sustain a positive pressure. The main tank also supports the internal and external components of the transformers. Main tank designs can be classified into 2 types: those being conservator type or sealed type. Conservator types have an externally-mounted tank that usually holds 10% of the main tank's volume. As the transformer oil expands and contracts due to system loading and ambient changes, the corresponding oil volume change must be accommodated. This tank is used to provide a holding mechanism for the expansion and contraction of the main tank's oil over these temperature variations. The liquid seal also provides some protection against moisture ingress into the insulation systems. A sealed tank design incorporates a gas header on top of the oil volume using nitrogen or dry air. This gas header can be either in a positive pressure or vacuum mode depending on the system loading or ambient changes. The pressure and vacuum conditions of a sealed tank design are controlled by the use of a regulator that ensures the tank is within its design limits.

Bushings are used to facilitate the egress of conductors to connect ends of the coils to a power supply system in an insulated, sealed (oil-tight and weather-tight) manner. A bushing is typically composed of an outer porcelain body mounted on a metallic flange. The phase leads are either independent paper-insulated or are an integral part of the bushing. At higher voltage levels, additional insulation is incorporated in the form of mineral oil and/or wound paper leads installed within the porcelain column.

The purpose of a cooling system in a power transformer is to efficiently dissipate heat generated due to copper and iron losses and to help maintain the windings and insulation temperature within acceptable range. The utilization of a number of cooling stages allows for an increase in load carrying capability. Loss of any stage or cooling element may result in a forced de-rating of the transformer. Transformer cooling system ratings are typically expressed as:

- Self-cooled (radiators) with designation as ONAN (oil natural, air natural)
- Forced cooling 2 stages (fans) with designation as ONAF (oil natural, air forced)

An off-load tap changer allows the transformer turns ratio to be altered over a small range to effect changes in output voltage as required. An off-load tap changer typically allows for an adjustment of 5% above nominal and 5% below nominal voltage in 2 ½ % steps. An off-load tap changer must only be operated with the transformer off potential. Under-load tap changers (ULTCs) allow for automatic voltage regulation in response to varying load conditions on the line. ULTCs consist of moving mechanical parts, a drive motor, linkages and voltage regulation sensing equipment. Instrument transformers include CT's and PTs for metering or control purposes. Power transformers are equipped with externally-mounted control cabinets for voltage and current control relay(s), secondary control circuits, and in some cases the tap changer motor and position indicators.

From the view of both financial and operational risk, power transformers are the most important asset deployed on the distribution and transmission systems. A significant proportion of power transformers employed by North American utilities were installed in the 1950s, 1960s or early 1970s. Despite the fact that the number of transformer failures arising due to End-of-Life (EOL) has to-date been relatively small, there is awareness that a majority of the transformer population will soon be reaching its end-of-life, which may significantly impact transformer failure rates.

1.1 Substation Transformers Degradation Mechanism

For a majority of transformers, EOL is expected to be spelled by the failure of insulation system and more specifically the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in service in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are presence of oxygen, high temperature and moisture.

Transformer oil is made up of complex hydrocarbon compounds, containing anti-oxidation compounds. Despite the presence of oxidation inhibitors, oxidation occurs slowly under normal operating conditions. The rate of oxidation is a function of internal operating temperature and age. The oxidation rate increases as the oil ages, reflecting both the depletion of the oxidation inhibitors and the catalytic effect of the oxidation products on the oxidation reactions. The products of oxidation of hydrocarbons are moisture, which causes further deterioration of the insulation system and organic acids, which result in formation of solids in the form of sludge. Increasing acidity and water levels result in the oil being more aggressive with regard to the paper and hence accelerate the ageing of the paper insulation. Formation of sludge adversely impacts the cooling capability of the transformer and adversely impacts its dielectric strength. An indication of the condition of insulating oil can be obtained through measurements of its acidity, moisture content and breakdown strength.

The paper insulation consists of long cellulose chains. As the paper ages through oxidization, these chains are broken. The tensile strength and ductility of insulting paper are determined by the average length of the cellulose chains; therefore, as the paper oxidizes the tensile strength and ductility are significantly reduced and insulating paper becomes brittle. The average length of the cellulose chains can be determined by measurement of the degree of polymerization (DP). However, this test can be performed only after de-tanking or the core and coil and therefore, is not a practical test. For a new transformer the DP value of the paper is normally greater than 1,000. As the paper ages this figure gradually decreases. When the DP value approaches below 250, the paper is in a very brittle and fragile condition. The lack of mechanical strength of paper insulation can result in failure if the transformer is subjected to mechanical shocks that may be experienced during normal operational situations.

In addition to the general oxidation of the paper, degradation and failure can also result from partial discharge (PD). PD can be initiated if the level of moisture is allowed to develop in the paper or if there are other minor defects within active areas of the transformer.
The relative levels of carbon dioxide and carbon monoxide dissolved in oil can provide an indication of paper degradation. Detection and measurement of Furans in the oil provides a more direct measure of the paper degradation. Furans are a group of chemicals that are created as a bi-product of the oxidation process of the cellulose chains. The occurrence of partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information related to the specification, operating history, loading conditions and system-related issues of a transformer provides a very effective means of assessing condition and helps to identify units at high risk of failure. It is the ideal platform on which to base an ongoing management strategy for aging transformers. The analysis helps to identify units that warrant consideration for continued use, makes consideration of remedial measures to extend life and identifies transformers that should be considered for replacement within a defined time frame.

Other condition assessment techniques for power transformers include the use of online monitors capable of monitoring specific parameters, e.g. dissolved gas monitors, continuous moisture measurement or temperature monitoring, winding continuity checks, DC insulation resistance measurements and no load loss measurements. Dielectric measurements that attempt to give an indication of the condition of the insulation system include dielectric loss, dielectric spectroscopy, polarization index and recovery voltage measurements. Doble testing is a procedure that falls within this general group. Other techniques that are commonly applied to transformers include infrared surveys, partial discharge detection and location using ultrasonics and/or electromagnetic detection and frequency response analysis.

Under-load tap changers are prone to failures resulting from either mechanical or electrical degradation. Active maintenance is required for tap changers in order to manage these issues. It is normal practice to maintain tap changers either at a fixed time interval or after a number of operations. During operation, wear of contacts and build up of oil degradation products, resulting from arcing activity during make and break of contacts, are the primary degradation processes. Maintenance, cleaning/replacement of contacts, defective components in the mechanism and changing/reprocessing of oil are the primary maintenance activities that deal with these issues. Oil analysis for tap changers is considered less useful than oil analysis for transformers due to the generation of gases and general degradation of the oil during arcing under normal ULTC operation.

There are a number of contributory factors to the long life of transformers. In the 1950s and 1960s transformers were designed and manufactured conservatively such that the thermal and electrical stresses, even at high load, were relatively low compared to modern designs. In addition, the loading of many of these transformers has been relatively light during their working life.

Consequences of power transformer failure include customer interruptions over significantly long durations. Catastrophic failure of a transformer may also result in injury or death, fire and damage to property. There are also environmental risks due to oil spills during tank failures. These risks are more pronounced where transformers are located near water bodies or contain PCBs.

1.2 Substation Transformers Health Index Formulation

This section presents the Health Index Formula that was developed and used for VC Substation Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

1.2.1 Substation Transformers Condition and Sub-Condition Parameters

Table 1-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	CPS Lookup Table
1	Insulation	6	Table 1-2
2	Cooling	1	Table 1-3
3	Sealing & connection	3	Table 1-4
4	Service Record	3	Table 1-5
	De-rating factor	As a multiplier for overall HI	Table 1-10

Table 1-2 Insulation (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Oil Quality	Table 1-6	1	4
2	Oil DGA	Table 1-7	2	4
3	Bushings	Table 1-8	1	4

Table 1-3 Cooling (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Cooling Fan	Table 1-8	1	4
2	Cooling Radiators	Table 1-8	2	4

Table 1-4 Sealing & Connection (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Tank/Conservator	Table 1-8	2	4
2	Gauges	Table 1-8	2	4
3	Oil Leaks	Table 1-8	5	4
4	Silica Gel	Table 1-8	2	4

Table 1-5 Service Record (m=4) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Loading	Table 1-9	5	4
2	Performance Record	Table 1-11	3	4
3	Age	Figure 1-1	1	4

1.2.2 Substation Transformers Condition Parameter Criteria

<u>**Oil Quality**</u>

Table 1-6 Oil Quality Test Criteria

CPF	Description
4	Overall factor is less than 1.2
3	Overall factor between 1.2 and 1.5
2	Overall factor is between 1.5 and 2.0
1	Overall factor is between 2.0 and 3.0
0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

Oil Quality Test	Voltage Class [kV]	Scores				
		1	2	3	4	Weight
Water Content (D1533) [ppm]	V ≤ 69	< 30	30-35	35-40	> 40	5
	69 < V < 230	< 20	20-25	25-30	> 35	
	V ≥ 230	< 15	15-20	20-25	> 25	
Dielectric Strength (D1816 - 2 mm gap) [kV]	V ≤ 69	> 40	35-40	30-35	< 30	4
	69 < V < 230	> 47	42-47	35-42	< 35	
	V ≥ 230	> 50	50-45	40-45	< 40	
Dielectric Strength (D877) [kV]	All	> 40	30-40	20-30	< 20	
IFT (D971) [dynes/cm]	V ≤ 69	> 25	20-25	15-20	< 15	4
	69 < V < 230	> 30	23-30	18-23	< 18	
	V ≥ 230	> 32	25-32	20-25	< 20	
Color	All	< 1.5	1.5-2.0	2.0-2.5	> 2.5	1
Acid Number (D974)	V ≤ 69	< 0.05	0.05-0.01	0.1-0.2	> 0.2	4

Oil Quality Test	Voltage Class [kV]	Scores				
		1	2	3	4	Weight
[mg KOH/g]	69 < V < 230	< 0.04	0.04-0.1	0.1-0.15	> 0.15	
	V ≥ 230	< 0.03	0.03-0.07	0.07-0.1	> 0.1	
Dissipation Factor (D924 - 25^{0}C)	All	< 0.5%	0.5%-1%	1-2%	> 2%	5
Dissipation Factor (D924 - 100^{0}C)	All	< 5%	5%-10%	10%-20%	> 20%	

Overall Factor = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

For example if all data is available, overall Factor = $\frac{\sum Score_i \times Weight_i}{12}$

<u>Oil DGA</u>

Table 1-7 Oil DGA Criteria

CPF	Description
4	DGA overall factor is less than 1.2
3	DGA overall factor between 1.2 and 1.5
2	DGA overall factor is between 1.5 and 2.0
1	DGA overall factor is between 2.0 and 3.0
0	DGA overall factor is greater than 3.0

*In the case of a score other than 4, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score 3, 0.85 for score 2, 0.75 for score 1 and 0.5 for score 0.

Where the DGA overall factor is the weighted average of the following gas scores:

2.5 MVA to 10 MVA

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=70	<=100	<=200	<=400	<=1000	>1000	**4**
CH4(Methane)	<=70	<=120	<=200	<=400	<=600	>600	**3**
C2H6(Ethane)	<=75	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=60	<=100	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=100	>100	**5**
CO2/CO	3 to 10	<=10to 12	<=12 to 15	15 to 18	18 to 20	>20	**4**

Overall Factor = $\dfrac{\sum Score_i \times Weight_i}{\sum Weight}$

Age

Assume that the failure rate for Substation Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 30 and 40 years the probability of failures (P_f) for this asset are 10% and 80% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below.

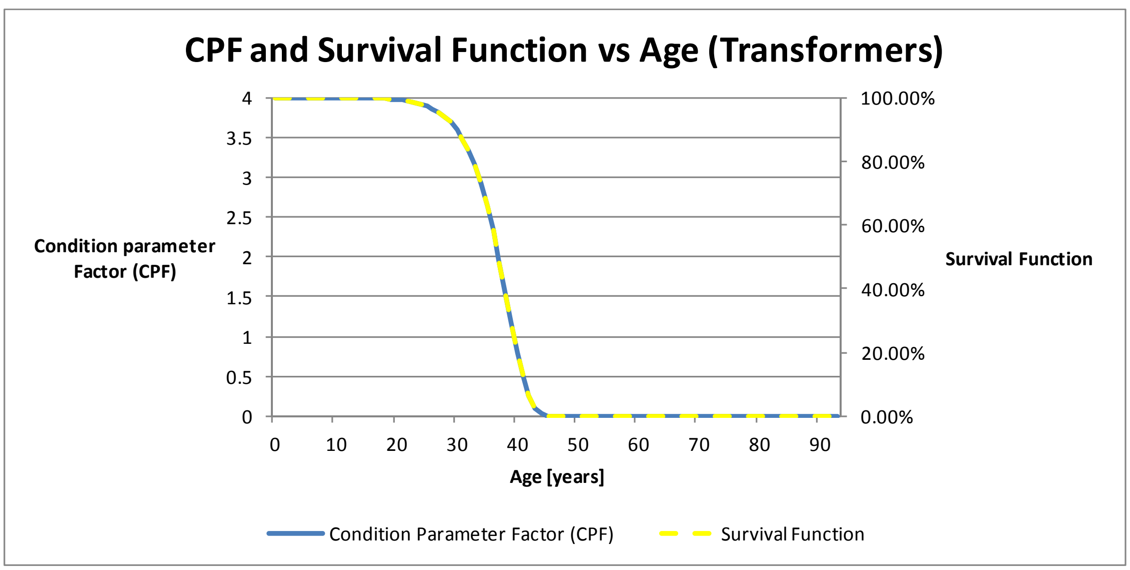

Figure 1-1 Substation Transformers Age Condition Criteria

Station Inspections

Table 1-8 Inspection Condition Criteria

CPF	Condition Description (Veridian Grading)
4	Good
2	Fair
0	Poor

Loading History

Table 1-9 Loading History

Data: S1, S2, S3, …, SN recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 CPF = $\frac{NA\times 4+NB\times 3+NC\times 2+ND\times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then CPF should be multiplied by 0.6 to show the effect of overheating.

Derating Factor

Table 1-10 De-Rating Factors

De-Rating Factor (DRF)	De-Rating Factor	Description
DRF	0.3	Rectangular winding transformers

1.3 Substation Transformers Age Distribution

The age distribution is shown in the figure below. Age was available for 67% of the population. The average age was found to be 29 years.

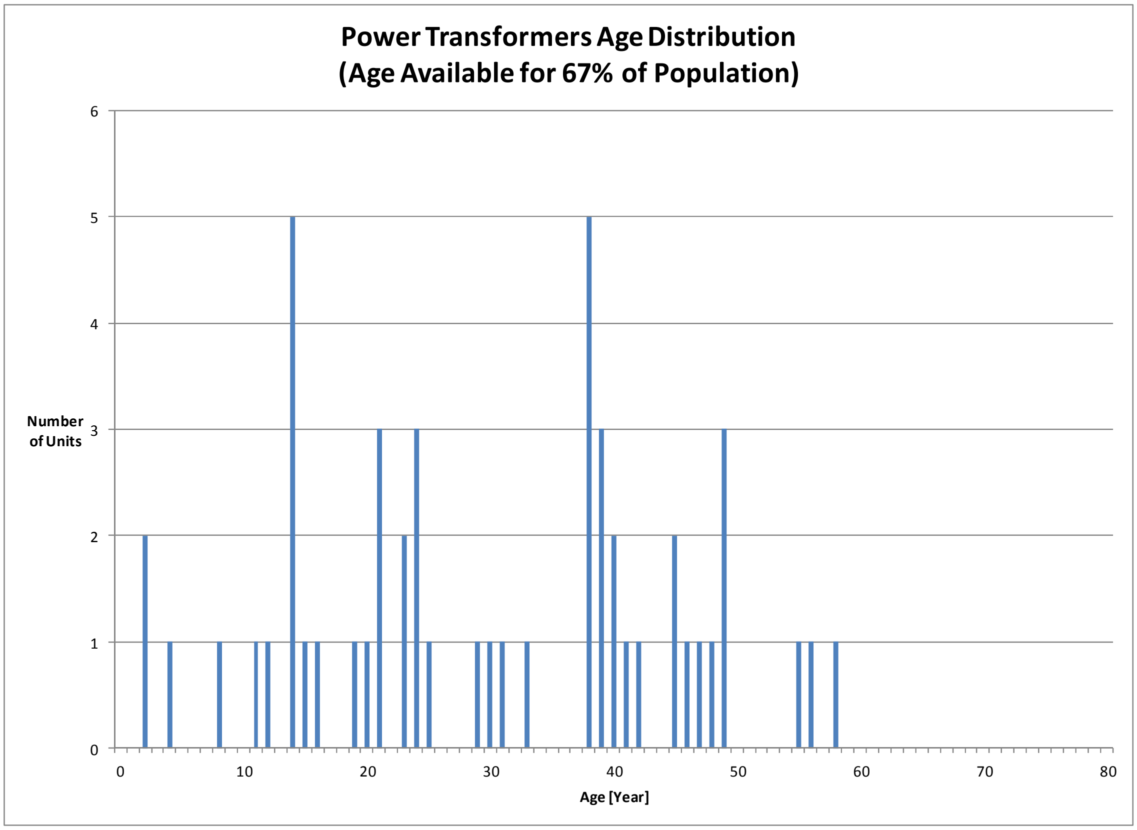

Figure 1-2 Substation Transformers Age Distribution

1.4 Substation Transformers Health Index Results

There are 79 in-service Substation Transformers at VC. Of these, 75 units had sufficient data for assessment.

The average Health Index for this asset group is 62%.

The Health Index Distribution is shown in Figure 1-3 and Figure 1-4.

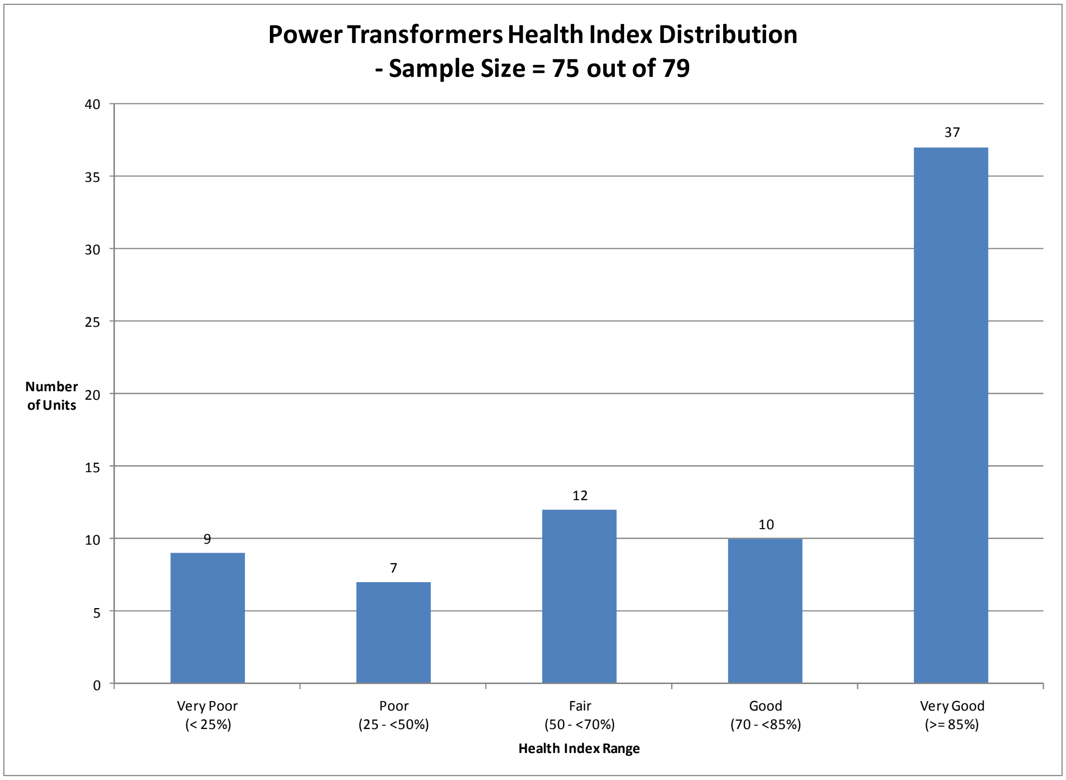

Figure 1-3 Substation Transformers Health Index Distribution (Number of Units)

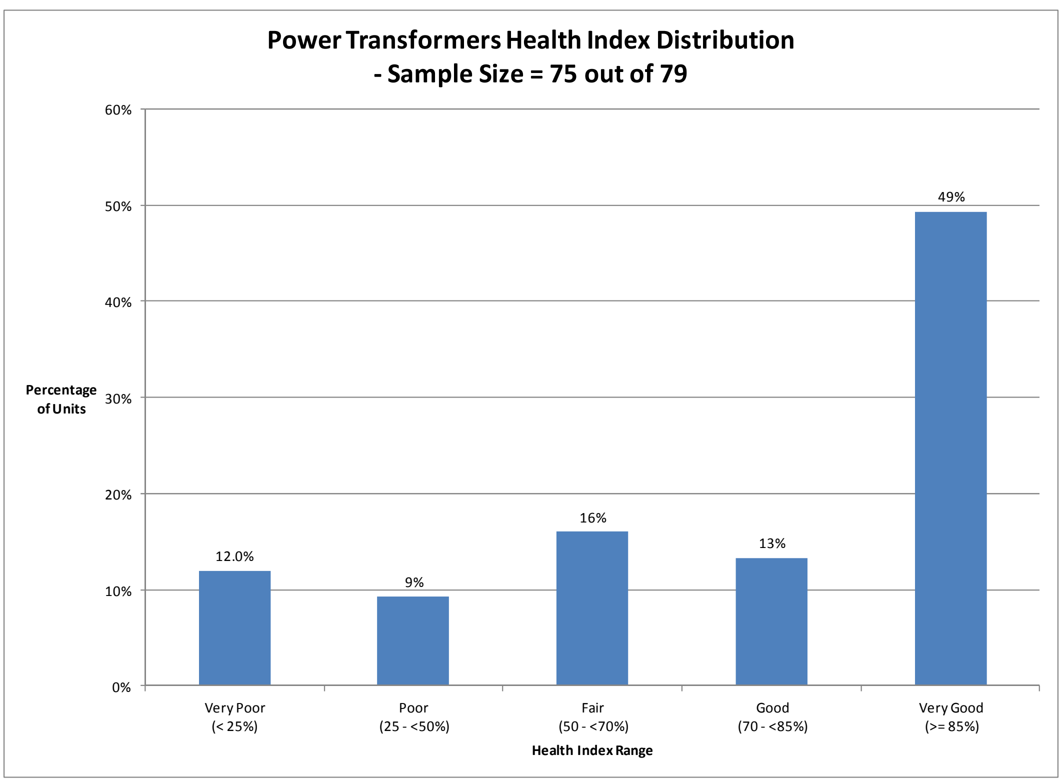

Figure 1-4 Substation Transformers Health Index Distribution (Percentage of Units)

The detailed results, from lowest to highest Health Index are shown below:

Table 1-11 Health Index Results for Each Substation Transformers Unit

	Transformer Name	Location	Age	Data Availability	Health Index (%)
1	SPARE-4	Beaverton Yard	60	9%	0
2	TORO-T2	Toronto	54	9%	0
3	SPARE-7	Belleville Yard	45	9%	0
4	SPARE-5	Greenwood	41	9%	12
5	SPARE-8	Harder SS	41	9%	12
6	SPARE-6	Belleville Yard	40	9%	20
7	WILL-T1	William J. Gillespie	52	46%	21
8	BAY-T1	Bay	45	81%	22
9	GREW-T1	Greenwood	40	61%	24
10	FAIR-T1	Fairport	39	65%	26
11	FAIR-T2	Fairport	39	65%	26
12	DOWT-T2	Dowty	16	92%	27
13	TOWN-T2	Town Centre	31	52%	28
14	SAND-T2	Sandy Beach	14	62%	29
15	MONA-T2	Monarch	21	62%	30
16	UXBE-T1	Uxbridge East	49	48%	39
17	CAVA-T1	Cavan South	55	48%	52
18	CAVA-T2	Cavan South	58	48%	54
19	BRAD-T1	Bradshaw	20	35%	57
20	CHUR-T1	Church	38	47%	59
21	CRAN-T1	Crandell	46	61%	59
22	WESH-T1	Westney Heights	23	62%	62
23	ARTT-T1	Art Thompson Arena	42	43%	63
24	MASN-T1	Mason Windows	40	81%	65
25	CATH-T1	Catharine	56	20%	67
26	PINE-REG	Pineridge (Regulator)	47	55%	67
27	WESH-T2	Westney Heights	22	62%	67
28	BAYR-T1	Bay Ridges	21	71%	68
29	PEAC-T1	Peacock	39	57%	72
30	MABL-T1	LR Mabley	25	57%	76
31	HERC-T1	Herchimer	38	82%	77
32	SPARE-10	Ajax Yard	33	9%	79
33	JONE-T1	Jones	49	62%	79
34	FIRS-T1	First	38	55%	80

	Transformer Name	Location	Age	Data Availability	Health Index (%)
35	HOWA-T1	Howard Walker	41	51%	82
36	CASC-T1	Cascade	45	62%	83
37	BELL-T1	Bell	14	62%	84
38	WILM-T1	Wilmot	43	61%	84
39	SQUI-T1	Squires Beach	26	60%	85
40	BIGE-T1	Bigelow	38	92%	86
41	EDGE-T1	Edgehill	48	93%	86
42	SHAN-T1	Shandex Sales	38	43%	86
43	SCUG-T1	Scugog	49	62%	86
44	SPRY-T1	Spry	8	38%	87
45	EDGE-T2	Edgehill	21	62%	88
46	SPRY-T2	Spry	14	36%	88
47	LIBN-T1	Liberty North	4	23%	88
48	TOWN-T1	Town Centre	41	52%	90
49	NOTI-T1	Notion	23	57%	91
50	RIVE-T1	Riverside	49	58%	91
51	PICB-T1	Pickering Beach	12	87%	92
52	UXBW-T1	Uxbridge West	38	69%	92
53	GRER-T1	Green River	14	82%	94
54	REID-T1	Reid	30	86%	94
55	JAME-T1	James D. Collins	24	60%	94
56	SIDN-T1	Sidney	29	96%	95
57	DOWT-T1	Dowty	23	96%	95
58	CAVN-T1	Cavan North	31	55%	96
59	LAID-T2	Laidlaw	2	55%	96
60	APPL-T1	Applecroft	24	62%	96
61	MAIN-T1	Main	15	62%	96
62	SQUI-T2	Squires Beach	26	60%	97
63	SPARE-2	Clarington Yard	25	9%	97
64	MONA-T1	Monarch	14	52%	97
65	APPL-T2	Applecroft	19	62%	99
66	TORO-T1	Toronto	22	50%	100
67	SAND-T1	Sandy Beach	14	60%	100
68	SHUT-T1	Shuter	24	60%	100
69	SUND-T1	Sunderland	23	82%	100
70	SPARE-3	Clarington Yard	10	9%	100
71	SPARE-14	Monarch SS	8	9%	100
72	JAMS-T1	James	11	20%	100

	Transformer Name	Location	Age	Data Availability	Health Index (%)
73	BEAW-T1	Beaverton West	8	69%	100
74	LAID-T1	Laidlaw	2	55%	100
75	HARD-T1	Harder		12%	100
76	SPARE-15	GE- Burlington		0%	
77	SPARE-12	Belleville		0%	
78	SPARE-13	Gravenhurst		0%	
79	SPARE-16	Gravenhurst		0%	

1.5 Substation Transformers Condition-Based Flagged-For-Action Plan

As it is assumed that Substation Transformers are proactively replaced, the risk assessment and replacement procedure described in Section II.2.3 was applied for this asset class.

As noted in Section II, a unit becomes a candidate for replacement when its risk, product of its *probability of failure* and *criticality*, is greater than or equal to one. The probability of failure is as determined by the Health Index. Criticality is determined as shown in the following section.

1.5.1 Substation Transformers Criticality

The minimum criticality, $Criticality_{min}$, is 1.25. This value is selected such that a unit with a probability of failure of 80% becomes a candidate for replacement (i.e. 80% * 1.25 = 1). The maximum criticality, $Criticality_{max,}$ is twice the base criticality ($Criticality_{max,}$ = 1.25*2 = 2.5).

Each unit's criticality is defined as follows:

$$Criticality = (Criticality_{max} - Criticality_{min}) * Criticality\_Multiple + Criticality_{min}$$

where the Criticality_Multiple (CM) is defined by criticality factors, weights, and scores:

$$CM = \frac{\sum_{CF=1}^{\forall CF}(CFS_{CF} \times WCF_{CF})}{\sum_{CF=1}^{\forall CF}(WCF_{CF})}$$

Where

CFS	Criticality Factor Score
WCF	Weight of Condition Factor

The factors, weights and the score system of each factor are as follows:

Table 1-12 Criticality Factors

Criticality Factor (CF)	Description	Weight (WCF)	Score (CFS)	
Load criticality	--- Number of customers --- Customer importance (e.g. hospitals, provincial buildings, restoration time sensitive customers)	30	Low	0
			High	1
Physical Protection	Oil containment, blast wall, deluge system	15	Yes	0
			No	1
Location	Public exposure, environmental impact	15	No	0
			Yes	1
Expected Outage Duration	Back-up unit unavailable, alternate feeds unavailable	20	No	0
			Yes	1
Operation & Maintenance	--- Obsolescence of spare parts (e.g. manufacturers cease to produce old types of spare parts) --- Known issues (e.g. not economical to have routine maintenance)	20	No	0
			Yes	1

1.5.2 Substation Transformers Flagged-For-Action Plan

The risk-based Flagged-For-Action Plan for Substation Transformers is plotted in Figure 1-5.

Such a plan flags a unit flagged for action in the year that its risk (product of POF and criticality) becomes greater than or equal to a preset minimum risk value.

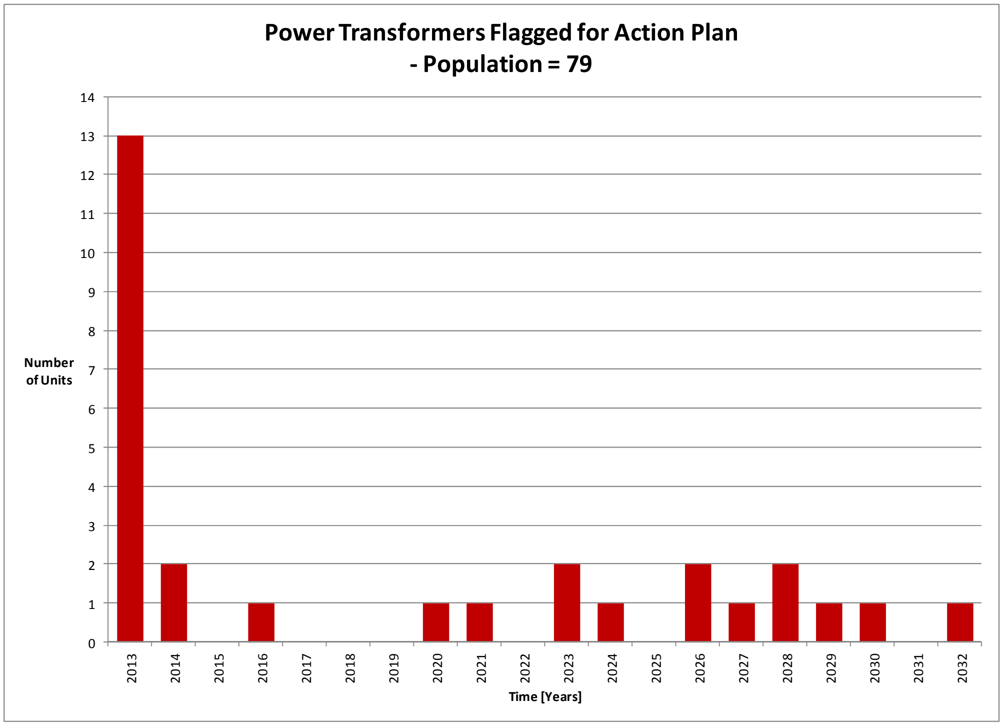

Figure 1-5 Substation Transformers Risk-Based Flagged-For-Action Plan

The risk based prioritization list is shown in Table 1-14.

Table 1-13 Risk Based Prioritization List for Substation Transformers

Rank	Transformer Name	Location	Age	Health Index (%)	Criticality Multiple	Action Year from Today
1	BAY-T1	Bay	45	22	0.65	0
2	DOWT-T2	Dowty	16	27	0.65	0
3	TOWN-T2	Town Centre	31	28	0.45	0
4	GREW-T1	Greenwood	40	24	0.35	0
5	WILL-T1	William J. Gillespie	52	21	0.15	0
6	FAIR-T1	Fairport	39	26	0.15	0
7	FAIR-T2	Fairport	39	26	0.15	0
8	SAND-T2	Sandy Beach	14	29	0.15	0
9	SPARE-4	Beaverton Yard	60	0	0	0
10	TORO-T2	Toronto	54	0	0	0
11	SPARE-7	Belleville Yard	45	0	0	0
12	SPARE-5	Greenwood	41	12	0	0
13	SPARE-8	Harder SS	41	12	0	0
14	MONA-T2	Monarch	21	30	0.15	1

Rank	Transformer Name	Location	Age	Health Index (%)	Criticality Multiple	Action Year from Today
15	SPARE-6	Belleville Yard	40	20	0	1
16	UXBE-T1	Uxbridge East	49	39	0.5	3
17	CAVA-T1	Cavan South	55	52	0.5	7
18	CAVA-T2	Cavan South	58	54	0.5	8
19	CHUR-T1	Church	38	59	0.45	10
20	BRAD-T1	Bradshaw	20	57	0.15	10
21	CRAN-T1	Crandell	46	59	0.5	11
22	WESH-T1	Westney Heights	23	62	0.15	13
23	ARTT-T1	Art Thompson Arena	42	63	0.15	13
24	MASN-T1	Mason Windows	40	65	0.15	14
25	CATH-T1	Catharine	56	67	0.15	15
26	WESH-T2	Westney Heights	22	67	0.15	15
27	BAYR-T1	Bay Ridges	21	68	0.15	16
28	PINE-REG	Pineridge (Regulator)	47	67	0	17
29	PEAC-T1	Peacock	39	72	0.5	19
30	MABL-T1	LR Mabley	25	76	0.2	>20
31	HERC-T1	Herchimer	38	77	0.35	>20
32	FIRS-T1	First	38	80	0.65	>20
33	JONE-T1	Jones	49	79	0.5	>20
34	HOWA-T1	Howard Walker	41	82	0.15	>20
35	SPARE-10	Ajax Yard	33	79	0	>20
36	CASC-T1	Cascade	45	83	0.45	>20
37	BELL-T1	Bell	14	84	0.45	>20
38	BIGE-T1	Bigelow	38	86	0.2	>20
39	SQUI-T1	Squires Beach	26	85	0.15	>20
40	EDGE-T1	Edgehill	48	86	0.15	>20
41	SHAN-T1	Shandex Sales	38	86	0.15	>20
42	SCUG-T1	Scugog	49	86	0.15	>20
43	WILM-T1	Wilmot	43	84	0	>20
44	EDGE-T2	Edgehill	21	88	0.45	>20
45	SPRY-T1	Spry	8	87	0.3	>20
46	SPRY-T2	Spry	14	88	0.3	>20
47	TOWN-T1	Town Centre	41	90	0.45	>20
48	LIBN-T1	Liberty North	4	88	0	>20
49	PICB-T1	Pickering Beach	12	92	0.3	>20
50	UXBW-T1	Uxbridge West	38	92	0.2	>20
51	NOTI-T1	Notion	23	91	0.15	>20
52	RIVE-T1	Riverside	49	91	0.15	>20

Rank	Transformer Name	Location	Age	Health Index (%)	Criticality Multiple	Action Year from Today
53	GRER-T1	Green River	14	94	0.35	>20
54	REID-T1	Reid	30	94	0.2	>20
55	DOWT-T1	Dowty	23	95	0.45	>20
56	SIDN-T1	Sidney	29	95	0.35	>20
57	CAVN-T1	Cavan North	31	96	0.3	>20
58	MAIN-T1	Main	15	96	0.3	>20
59	APPL-T1	Applecroft	24	96	0.15	>20
60	SQUI-T2	Squires Beach	26	97	0.15	>20
61	APPL-T2	Applecroft	19	99	0.15	>20
62	JAME-T1	James D. Collins	24	94	0	>20
63	SUND-T1	Sunderland	23	100	0.8	>20
64	JAMS-T1	James	11	100	0.35	>20
65	SHUT-T1	Shuter	24	100	0.3	>20
66	TORO-T1	Toronto	22	100	0.15	>20
67	SAND-T1	Sandy Beach	14	100	0.15	>20
68	BEAW-T1	Beaverton West	8	100	0.15	>20
69	LAID-T2	Laidlaw	2	96	0	>20
70	SPARE-2	Clarington Yard	25	97	0	>20
71	MONA-T1	Monarch	14	97	0	>20
72	SPARE-3	Clarington Yard	10	100	0	>20
73	SPARE-14	Monarch SS	8	100	0	>20
74	LAID-T1	Laidlaw	2	100	0	>20
75	HARD-T1	Harder		100	0	>20
76	SPARE-15	GE- Burlington			0	
77	SPARE-12	Belleville			0	
78	SPARE-13	Gravenhurst			0	
79	SPARE-16	Gravenhurst			0	

1.6 Substation Transformers Data Analysis

The data available for Substation Transformers includes age, inspection results, oil quality, dissolved gas analysis, winding dissipation factors, and loading.

1.6.1 Substation Transformers Data Availability Distribution

The average DAI for Substation Transformers is 50%. The data availability distribution for the population is shown in Figure 1-6.

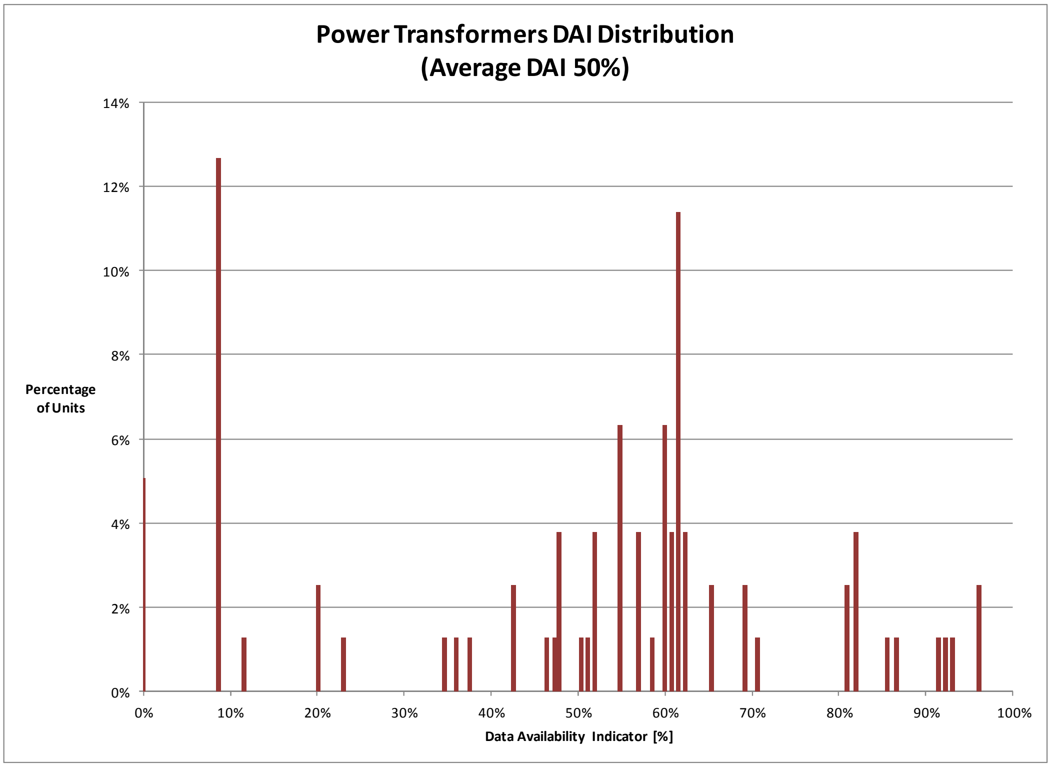

Figure 1-6 Substation Transformers Data Availability Distribution

1.6.2 Substation Transformers Data Gap

For this asset category, most of the critical data, namely test data, are already available and included in the Health Index formula.

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2 Substation Breakers

Circuit breakers used in transmission and distribution power systems to sectionalize and isolate circuits are often categorized by the insulation medium used in the breaker and the interruption process. The common breaker types include oil circuit breakers, air circuit breakers, vacuum circuit breakers, and SF6 circuit breakers.

Oil circuit breakers (OCB) have been in use for over 70 years. OCBs interrupt current under oil and use the gas generated by the decomposition of the oil to assist in arc extinguishing. They are available in single or multi-tank configurations. Two types of designs exist among OCBs: bulk oil breakers (in which oil serves as the insulating and arc quenching medium), and minimum oil breakers (in which oil provides the arc quenching function only).

Air insulated breakers are generally used at distribution system voltages and below. Air-type circuit breakers fall into two classifications: air- blast and air- magnetic. Air-blast breakers use compressed air as the quenching, insulating and actuating mechanism. In a typical device a blast of air carries the arc into an arc chute to be extinguished. Air blast breakers at distribution voltages are often in metal-enclosed switchgear. Continuous current ratings of these devices are in the range of 1200 to 5000 A, and fault interrupting from 20 to 140kA.

Air magnetic breakers use the magnetic effect of the current undergoing interruption to draw an arc into an arc chute for cooling, splitting and extinction. Sometimes, an auxiliary puffer or air blast piston may help interrupt low-level currents. These designs are commonly used in metal-clad switchgear applications. Air magnetic breakers are available in voltages ratings up to 15kV, with continuous currents up to 3000A, and interrupting ratings as high as 40 kA. These breakers are relatively inexpensive and relatively easy to maintain. The air magnetic breakers have short duty cycles, require frequent maintenance and approach their end-of-life at much faster rates than either SF6 or vacuum breakers. They also have limited transient recovery voltage capabilities and can experience re-strike when switching capacitive currents.

In vacuum breakers, the parting contacts are placed in an evacuated chamber (i.e. bottle). There is generally one fixed and one moving contact in a butting configuration. A bellows attached to the moving contact permits the required short stroke to occur while maintaining the vacuum. Arc interruption occurs at current zero after withdrawal of the moving contact. Utilities typically install vacuum breakers indoors in metal-clad switchgear. Current medium voltage vacuum breakers require low mechanical drive energy, have high endurance, can interrupt fully rated short circuits up to 100 times, and operate reliably over 30,000 or more switching operations. Vacuum breakers also are safe and protective of the environment.

SF6 Circuit breakers were first developed in the late 1960s and based on air blast technology. SF6 breakers interrupt currents by opening a blast valve and allowing high pressure SF6 to flow through a nozzle along the arc drawn between fixed and moving contacts. This process rapidly deionizes, cools and interrupts the arc. After interruption, low-pressure gas is compressed for re-use in the next operation.

2.1 Substation Breakers Degradation Mechanism

In general, circuit breakers have many moving parts that are subject to wear and stress. They frequently "make" and "break" high currents and experience the erosion caused by arcing accompanying these operations. All circuit breakers undergo some contact degradation every time they open to interrupt an arc. Also, arcing produces heat and decomposition products that degrade surrounding insulation materials, nozzles, and interrupter chambers. The mechanical energy needed for the high contact velocities of these assets adds mechanical deterioration to their degradation processes.

The rate and severity of degradation depends on many factors, including insulating and conducting materials, operating environments, and a breaker's specific duties. Outdoor circuit breakers may experience adverse environmental conditions that influence their rate and severity of degradation. For outdoor mounted circuit breakers, the following represent additional degradation factors:

- Corrosion
- Effects of moisture
- Bushing/insulator deterioration
- Mechanical

Corrosion and moisture commonly cause degradation of internal insulation, breaker performance mechanisms, and major components like bushings, structural components, and oil seals. Corrosion presents problems for almost all circuit breakers, irrespective of their location or housing material. Rates of corrosion degradation, however, vary depending on exposure to environmental elements. Underside tank corrosion causes problem in many types of breakers, particularly those with steel tanks. Another widespread problem involves corrosion of operating mechanism linkages that result in eventual link seizures. Corrosion also causes damage to metal flanges, bushing hardware and support insulators.

Moisture causes degradation of the insulating system. Outdoor circuit breakers experience moisture ingress through defective seals, gaskets, pressure relief and venting devices. Moisture in the interrupter tank can lead to general degradation of internal components. Also, sometimes free water collects in tank bottoms, creating potential catastrophic failure conditions.

For circuit breakers, mechanical degradation presents greater end-of-life concerns than electrical degradation. Generally, operating mechanisms, bearings, linkages, and drive rods represent components that experience most mechanical degradation problems. Oil leakage also occurs. Contacts, nozzles, and highly stressed components can also experience electrical-related degradation and deterioration. Other effects that arise with aging include:

- Loose primary and grounding connections
- Oil contamination and/or leakage
- Deterioration of concrete foundation affecting stability of breaker

For OCBs, the interruption of load and fault currents involves the reaction of high pressure with large volumes of hydrogen gas and other arc decomposition products. Thus, both contacts and oil degrade more rapidly in OCBs than they do in vacuum designs, especially when the OCB undergoes frequent switching operations. Generally, 4 to 8 fault interruptions with contact erosion and oil carbonisation will lead to the need maintenance, including oil filtration. Oil breakers can also experience restrike when switching low load or line charging currents with high recovery voltage values. Sometimes this can lead to catastrophic breaker failures.

The diagnostic tests to assess the condition of circuit breakers include:

- Visual inspections
- Travel time tests
- Contact resistance measurements
- Bushing - Doble Test
- Stored energy tests (Air/Hydraulic/Spring Recharge Time)
- Insulating medium tests

As indicated above, the useful life of circuit breakers can vary significantly depending on the duty cycle and typically lies within a broad range of 25 to 50 years.

In some cases, the end of life for circuit breakers may not be governed by technical considerations but rather by operational, maintenance and obsolescence issues. The International Council on Large Electric Systems' (CIGRE) has identified the following factors that lead to end-of-life for this asset class:

- Decreasing reliability, availability and maintainability
- High maintenance and operating costs
- Changes in operating conditions, rendering the existing asset obsolete;
- Maintenance overhaul requirements; and

Consequences of circuit breaker failure may be significant as they can directly lead to catastrophic failure of the protected equipment, leading to customer interruptions, health and safety consequences and adverse environmental impacts.

2.2 Substation Breakers Health Index Formula

This section presents the Health Index Formula that was developed and used for VC's Circuit Breakers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

2.2.1Substation Breakers Condition and Sub-Condition Parameters

Table 2-1 Substation Breakers Condition Weights and Maximum CPS

m	Condition parameter	WCP_m				CPS Lookup Table
		Oil	Vacuum	Air	SF6	
1	Operating mechanism	14	7	14	14	Table 2-2
2	Contact performance	7	7	7	7	Table 2-3
3	Arc extinction	9	2	5	5	Table 2-4
4	Insulation	2	2	2	2	Table 2-5
5	Service Record	5	5	5	5	Table 2-6
	Derating Factor	As a multiplier for overall HI				Table 2-11

Table 2-2 Substation Breakers Contact Performance (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Operating Mechanism	Table 2-7	2	4
2	Electrical Operation	Table 2-7	1	4
3	Manual Operation	Table 2-7	1	4

Table 2-3 Substation Breakers Arc Extinction (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Stationary Contact	Table 2-7	1	4
2	Moving Contact	Table 2-7	1	4
3	Arcing Contact	Table 2-7	1	4
4	Contact Resistance	Table 2-8	2	4

Table 2-4 Substation Breakers Arc Extinction (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF lookup table	$WCPF_n$				$CPF_{n.max}$
			Oil	Vacuum	Air	SF6	
1	Cell Space Heater	Table 2-7	1	1	1	1	4
2	Leak Interrupter	Table 2-7	2	2	2	2	4
3	Arc Chute	Table 2-7	1	1	1	1	4

Table 2-5 Insulation (m=4) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
2	Insulation Resistance	Table 2-10	1	4

Table 2-6 Substation Breakers Service Record (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Result	Table 2-7	2	4
2	Age	Figure 2-1	1	4

2.2.2 Substation Breakers Condition Parameter Criteria

Station Inspections

Table 2-7 Inspection Condition Criteria

CPF	Condition Description (Veridian Grading)
4	Satisfactory
0	Needs Improvement

Station Measurement

Breaker contact resistance measurements indicate the proper function of the breaker as designed. It is crucial that the breaker meets these specifications for proper and reliable operation

Table 2-8 Resistance Test Criteria

Score	Condition Description
4	Measurement <= 80% Specification limit
3	Measurement (80%, 100%] specification limit
1	Measurement (100%, 120%] specification limit
0	Measurement > 120% specification limit

Where specification limit is defined in the following table

Table 2-9 Contact resistance specification limit

CB type	Limit
Oil	300 U OHM
SF6	150 U OHM
Vacuum & air magnet	250 U OHM

Table 2-10 Insulation Resistance Condition Criteria

Condition Rating	CPF	Description (15 kV)
PASS	4	>= 5000 MOhm
FAIL	0	< 5000 MOhm

2.2.3 Individual Condition Based on CB Intrinsic Characteristics

--- Age

Assume that the failure rate for circuit breakers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 20 and 45 years the probabilities of failure (P_f) are 20% and 90% result in the survival curves shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below.

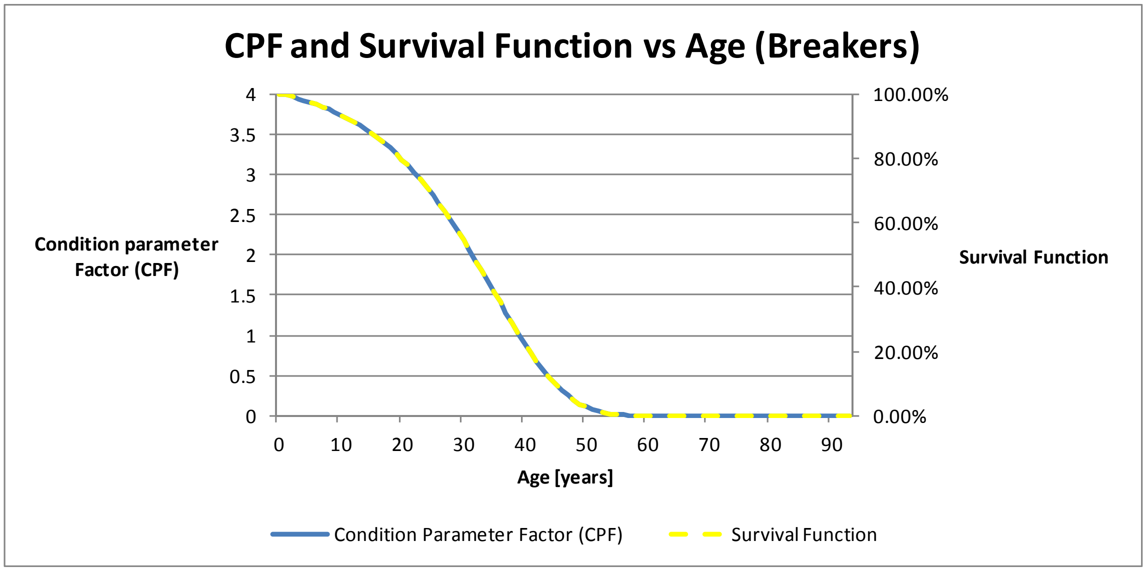

Figure 2-1 CPF and Survival Function vs. Age (Circuit Breakers)

2.2.4 Individual Condition Based on Operation Mode

<u>Derating Factor</u>

Table 2-11 De-Rating Factors

De-Rating Factor	Description
0.3	Type A breakers

2.3 Substation Breakers Age Distribution

The age distribution is shown in the figure below. Age was available for 83% of the population. The average age was found to be 28 years.

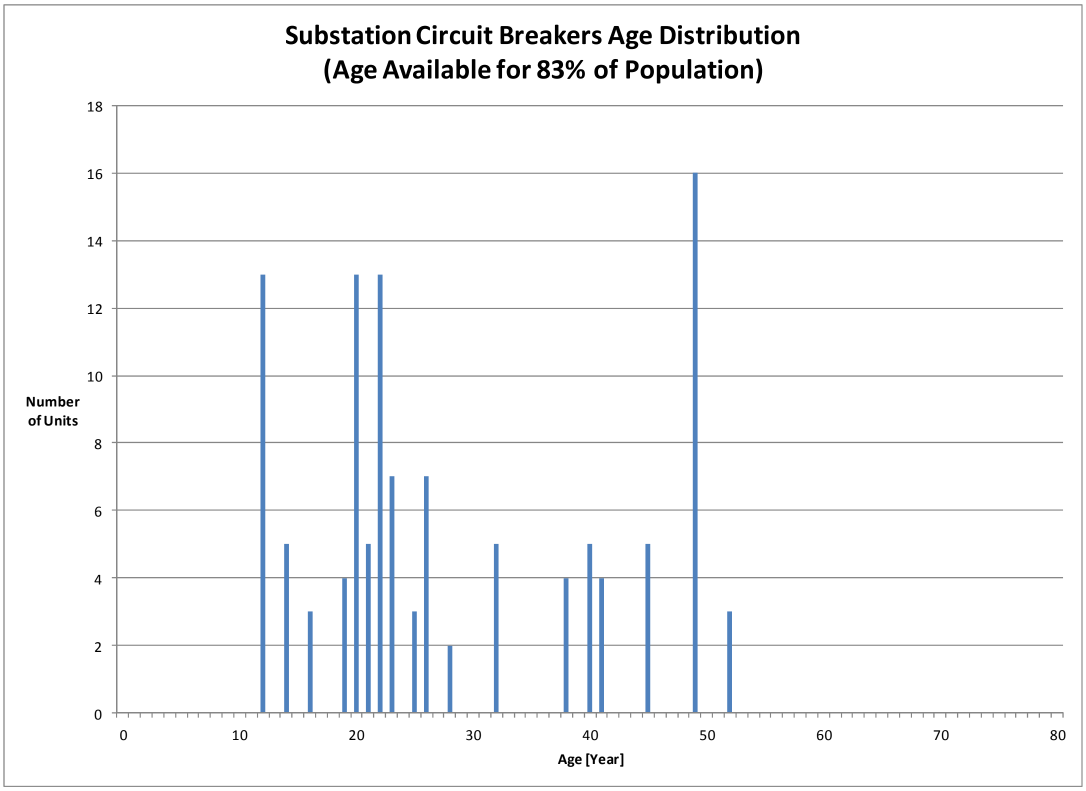

Figure 2-2 Substation Breakers Age Distribution

2.4 Substation Breakers Health Index Results

There are 141 in-service Substation Breakers at VC. Among them, 129 have data for assessment.

The average Health Index for this asset group is 86%. Approximately 4.7% of the units were found to be in poor or very poor condition.

The Health Index Distribution is shown in Figure 1-3 and Figure 1-4.

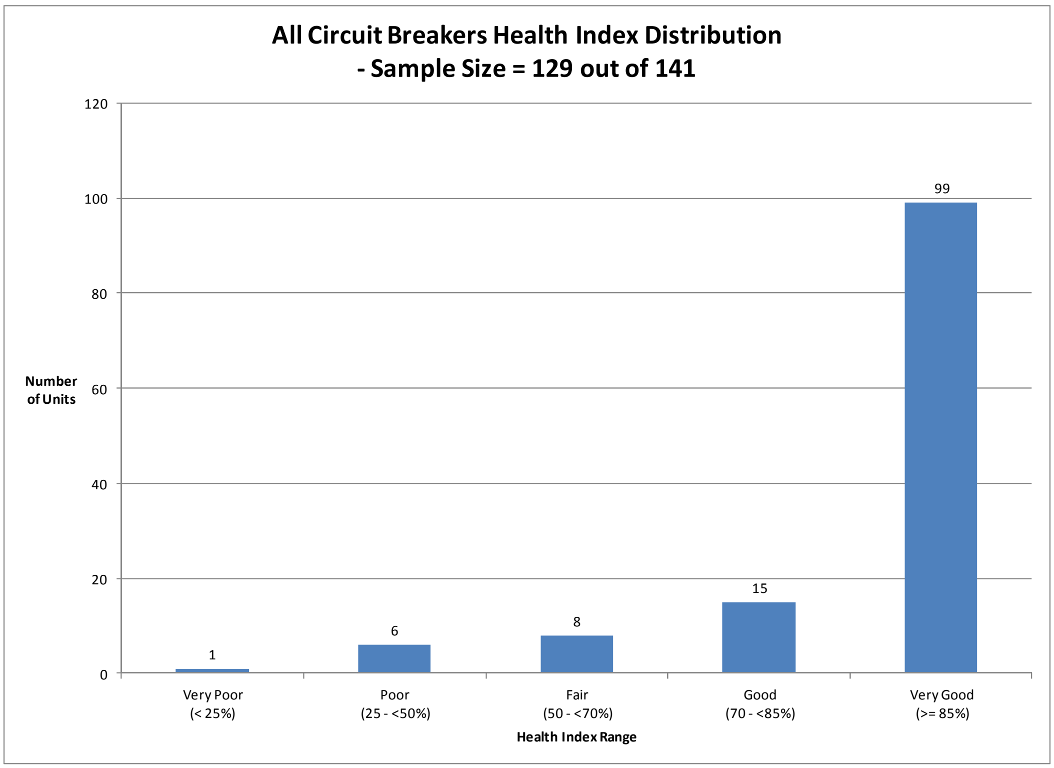

Figure 2-3 Substation Breakers Health Index Distribution (Number of Units)

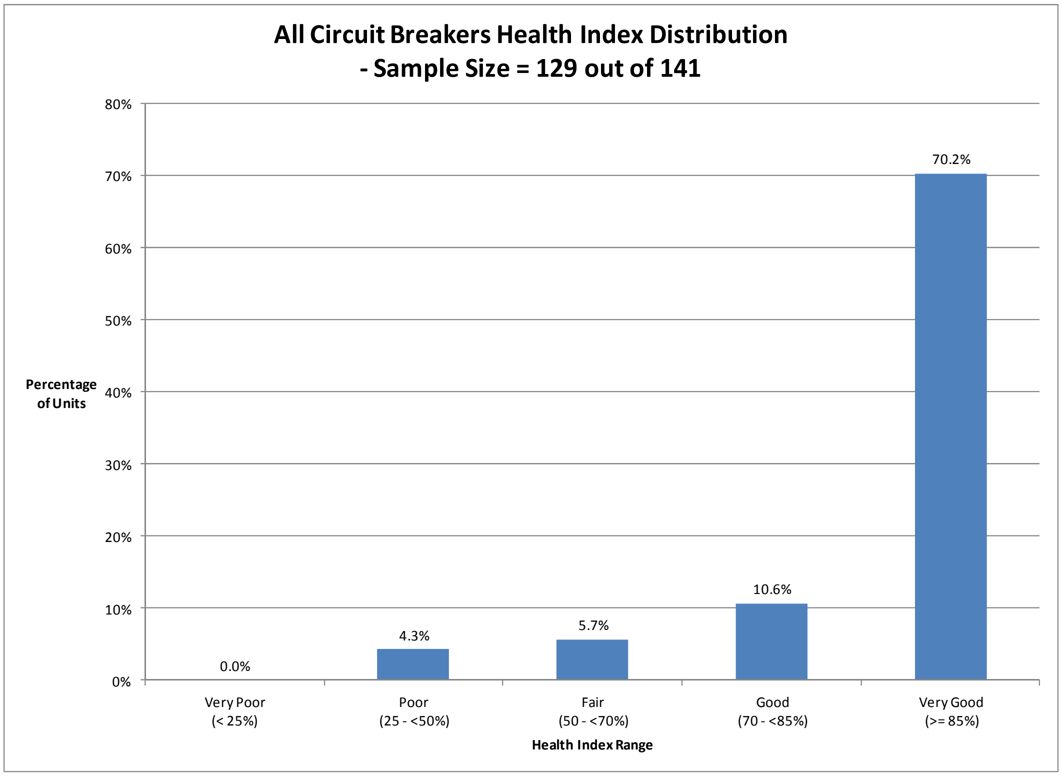

Figure 2-4 Substation Breakers Health Index Distribution (Percentage of Units)

The detailed results, from lowest to highest Health Index are shown below:

Table 2-12 Health Index Results for Each Substation Breakers Unit

	Circuit Breaker Name	Type	Age	Data Availability	Health Index (%)
1	TORO-F1	SCB	20	24%	21
2	TORO-F2	SCB	20	14%	27
3	WILM-F3	SCB	20	58%	29
4	TORO-F3	SCB	20	72%	30
5	WILM-F2	SCB	20	72%	30
6	WILM-F1	SCB	20	63%	30
7	SQUI-TB	SCB	26	57%	42
8	UXBE-F3	OCB	49	72%	56
9	EDGE-T1	OCB	52	12%	59
10	JONE-F4	ACB	49	14%	60
11	JONE-F5	ACB	49	14%	60
12	TOWN-T1	ACB	41	14%	66
13	SQUI-F3	SCB	26	76%	67
14	CHUR-F2	ACB	40	14%	68

	Circuit Breaker Name	Type	Age	Data Availability	Health Index (%)
15	TOWN-T2	ACB	40	14%	68
16	UXBE-F1-K2	OCB	49	72%	69
17	UXBE-F2-K2	OCB	49	72%	69
18	SPRY-TB1	VCB	19	70%	72
19	SPRY-F3	VCB	12	85%	73
20	APPL-F3	SCB	23	30%	83
21	SQUI-T1	SCB	26	76%	83
22	CHUR-F1	ACB	40	59%	83
23	SIDN-F1	SCB	28	14%	84
24	APPL-T2	SCB	23	45%	85
25	TOWN-F3	ACB	40	89%	86
26	DOWT-F1	SCB	25	14%	87
27	DOWT-F2	SCB	25	14%	87
28	DOWT-TB	VCB	25	19%	87
29	JONE-F6	ACB	49	81%	87
30	JONE-F7	ACB	49	81%	87
31	GREW-F3	OCB		43%	88
32	SQUI-F4	SCB	26	76%	88
33	LIBN-F1	VCB	20	85%	89
34	SPRY-T1	VCB	19	70%	89
35	EDGE-F1	VCB	22	81%	90
36	EDGE-F2	VCB	22	81%	90
37	BELL-T1	VCB	14	85%	90
38	PICB-F4	VCB	12	85%	90
39	SPRY-F4	VCB	12	70%	90
40	SPRY-F5	VCB	12	70%	90
41	SPRY-T2	VCB	12	70%	90
42	SPRY-F1	VCB	19	87%	90
43	SPRY-F2	VCB	19	87%	90
44	GRER-F3	OCB		52%	90
45	GREW-F1	OCB		52%	90
46	EDGE-F3	OCB	52	74%	90
47	MONA-F4	ACB	38	67%	90
48	LIBN-T1	VCB		66%	90
49	NOTI-F4	SCB	21	14%	91
50	NOTI-T1	SCB	21	14%	91
51	SQUI-F1	SCB	26	72%	91
52	SAND-F5	OCB	22	72%	91
53	SAND-F6	OCB	22	72%	91

	Circuit Breaker Name	Type	Age	Data Availability	Health Index (%)
54	SIDN-F2	SCB	28	84%	92
55	NOTI-F1	SCB	21	67%	93
56	NOTI-F2	SCB	21	67%	93
57	UXBE-F1-K1	OCB	49	82%	94
58	UXBE-F2-K1	OCB	49	82%	94
59	JONE-T1	ACB	49	72%	94
60	JONE-F3	ACB	49	59%	94
61	RIVE-F1	OCB	49	64%	94
62	RIVE-F2	OCB	49	72%	94
63	RIVE-F3	OCB	49	45%	94
64	RIVE-F4	OCB	49	45%	94
65	RIVE-T1	OCB	49	45%	94
66	DOWT-F3	VCB	16	19%	94
67	DOWT-F4	VCB	16	19%	94
68	DOWT-T2-K2	VCB	16	19%	94
69	APPL-F1	SCB	23	89%	94
70	MBDN-F1	OCB		77%	95
71	MBDN-F2	OCB		77%	95
72	CVSC-F2	ACB	45	59%	95
73	CVSC-F3	ACB	45	59%	95
74	CVSC-F4	ACB	45	59%	95
75	TOWN-F1	ACB	41	72%	95
76	TOWN-F2	ACB	41	72%	95
77	EDGE-F4	OCB	52	69%	95
78	CVSC-T1	ACB	45	63%	95
79	CVSC-F1	ACB	45	63%	95
80	MONA-F1	VCB	14	19%	95
81	HERC-F3F4	ACB	38	72%	96
82	TOWN-TB	ACB	41	89%	96
83	TOWN-F4	ACB	40	89%	96
84	MONA-F3	ACB	38	63%	96
85	HERC-F1F2	ACB	38	63%	96
86	WESH-F1	ACB	32	63%	97
87	WESH-F2	ACB	32	63%	97
88	WESH-F3	ACB	32	63%	97
89	WESH-F4	ACB	32	63%	97
90	WESH-TB	ACB	32	63%	97
91	EDGE-T2	VCB	22	72%	98
92	SQUI-F2	SCB	26	76%	98

	Circuit Breaker Name	Type	Age	Data Availability	Health Index (%)
93	SQUI-T2	SCB	26	76%	98
94	BRAD-F1	VCB	20	85%	98
95	BRAD-F2	VCB	20	85%	98
96	BRAD-F3	VCB	20	85%	98
97	BRAD-T1	VCB	20	85%	98
98	LIBN-F2	VCB	20	70%	98
99	LIBN-F3	VCB	20	70%	98
100	APPL-F4	SCB	23	81%	98
101	APPL-T1	SCB	23	81%	98
102	APPL-TB	SCB	23	72%	98
103	FBDR-F1	OCB	22	63%	98
104	FBDR-F2	OCB	22	63%	98
105	FBDR-F3	OCB	22	63%	98
106	BAYR-F1	OCB	22	64%	99
107	SAND-F1	OCB	22	45%	99
108	SAND-F2	OCB	22	45%	99
109	APPL-F2	SCB	23	89%	99
110	NOTI-F3	SCB	21	63%	99
111	BAYR-F2	OCB	22	82%	99
112	BAYR-F3	OCB	22	82%	99
113	PICB-TB	VCB	12	61%	99
114	MONA-F2	VCB	14	70%	99
115	BELL-F1	VCB	14	85%	99
116	BELL-F2	VCB	14	87%	99
117	PICB-F1	VCB	12	85%	99
118	PICB-F2	VCB	12	85%	99
119	PICB-F3	VCB	12	85%	99
120	PICB-F5	VCB	12	73%	99
121	PICB-F6	VCB	12	73%	99
122	PICB-T1	VCB	12	73%	99
123	PICB-T2	VCB	12	73%	99
124	DOWT-T2-K1	SCB		63%	100
125	44-R2L	OCB		55%	100
126	44-ABL	OCB		58%	100
127	JONE-T	OCB		60%	100
128	JBHE-F1-K2	OCB		58%	100
129	JBHE-F2-K2	OCB		58%	100
130	REID-F1	SCB		0%	
131	REID-F2	SCB		0%	

	Circuit Breaker Name	Type	Age	Data Availability	Health Index (%)
132	BEAW-F1	ACB		0%	
133	BEAW-F2	ACB		0%	
134	LBDD-F1	OCB		0%	
135	LBDD-F2	OCB		0%	
136	JBHE-F1-K1	OCB		0%	
137	JBHE-F2-K1	OCB		0%	
138	JBHE-F3	OCB		0%	
139	JBHE-F4	OCB		0%	
140	SHUT-F1	OCB		0%	
141	SHUT-F2	OCB		0%	

2.5 Substation Breakers Condition-Based Flagged-For-Action Plan

As it is assumed that Substation Breakers are proactively replaced, the risk assessment and replacement procedure described in Section II.2.3 was applied for this asset class.

As noted in Section II, a unit becomes a candidate for replacement when its risk, product of its *probability of failure* and *criticality*, is greater than or equal to one. The probability of failure is as determined by the Health Index. Criticality is determined as shown in the following section.

2.5.1 Substation Breakers Criticality

The minimum criticality, Criticality_{min}, is 1.25. This value is selected such that a unit with a probability of failure of 80% becomes a candidate for replacement (i.e. 80% * 1.25 = 1). The maximum criticality, $\text{Criticality}_{max,}$ is twice the base criticality ($\text{Criticality}_{max,}$ = 1.25*2 = 2.5).

Each unit's criticality is defined as follows:

$$\text{Criticality} = (\text{Criticality}_{max} - \text{Criticality}_{min})*\text{Criticality\_Multiple} + \text{Criticality}_{min}$$

where the Criticality_Multiple (CM) is defined by criticality factors, weights, and scores:

$$CM = \frac{\sum_{CF=1}^{\forall CF}(CFS_{CF} \times WCF_{CF})}{\sum_{CF=1}^{\forall CF}(WCF_{CF})}$$

Where

CFS	Criticality Factor Score
WCF	Weight of Condition Factor

The factors, weights and the score system of each factor are as follows:

Table 2-13 Substation Breakers Criticality Factors

Criticality Factor (CF)	Description	Weight (WCF)	Score (CFS)	
Load criticality	--- Number of customers --- Customer importance (e.g. hospitals, provincial buildings, restoration time sensitive customers)	25	Low	0
			High	1
Long-term Development	system upgrading (e.g. higher voltage level, higher fault duty to be implemented)	20	No	0
			Yes	1
Operation & Maintenance	--- obsolescence of spare parts (e.g. manufacturers cease to produce old types of spare parts) --- known issues (e.g. not economical to have routine maintenance)	20	No	0
			Yes	1
Environmental & Safety	--- Legislation/standard requirement (e.g. replace SF6, oil CBs) --- Safety concern (e.g. arc resistance feature, remote racking feature)	35	No	0
			Yes	1

2.5.2 Substation Breakers Flagged-For-Action Plan

The riak-based Flagged-For-Action Plan for Substation Breakers is plotted in Figure 2-5.

Such a plan flags a unit flagged for action in the year that its risk (product of POF and criticality) becomes greater than or equal to one.

The risk based prioritization list is shown in Table 2-14.

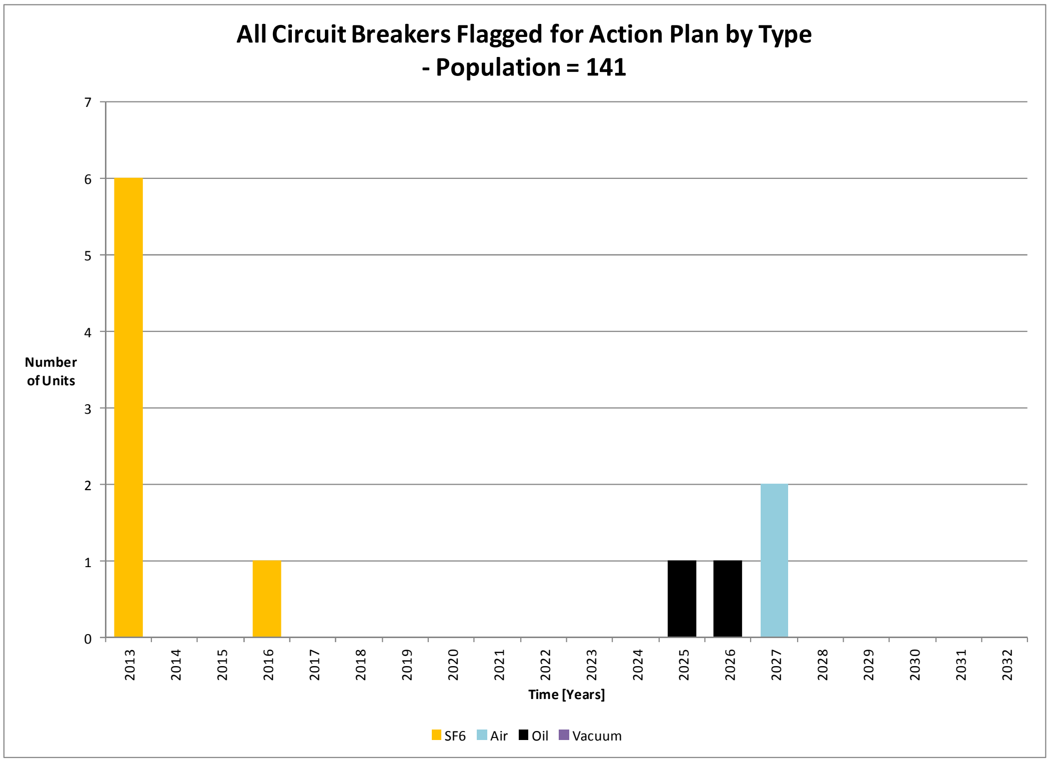

Figure 2-5 Substation Breakers Risk-Based Flagged-For-Action Plan

Table 2-14 Risk Based Prioritization List for Substation Breakers

Rank	Circuit Breaker Name	Type	Age	Health Index (%)	Criticality Multiple	Action Year from Today
1	TORO-F1	SCB	20	21	0.55	0
2	TORO-F2	SCB	20	27	0.55	0
3	WILM-F3	SCB	20	29	0.55	0
4	TORO-F3	SCB	20	30	0.55	0
5	WILM-F2	SCB	20	30	0.55	0
6	WILM-F1	SCB	20	30	0.55	0
7	SQUI-TB	SCB	26	42	0.6	3
8	UXBE-F3	OCB	49	56	0.2	12
9	EDGE-T1	OCB	52	59	0.2	13
10	JONE-F4	ACB	49	60	0.55	14
11	JONE-F5	ACB	49	60	0.55	14
12	TOWN-T1	ACB	41	66	0.6	20
13	SQUI-F3	SCB	26	67	0.35	20

Rank	Circuit Breaker Name	Type	Age	Health Index (%)	Criticality Multiple	Action Year from Today
14	CHUR-F2	ACB	40	68	0.55	>20
15	TOWN-T2	ACB	40	68	0.6	>20
16	UXBE-F1-K2	OCB	49	69	0.2	>20
17	UXBE-F2-K2	OCB	49	69	0.2	>20
18	SPRY-TB1	VCB	19	72	0.25	>20
19	SPRY-F3	VCB	12	73	0	>20
20	APPL-F3	SCB	23	83	0.35	>20
21	SQUI-T1	SCB	26	83	0.6	>20
22	CHUR-F1	ACB	40	83	0.55	>20
23	SIDN-F1	SCB	28	84	0.35	>20
24	APPL-T2	SCB	23	85	0.6	>20
25	TOWN-F3	ACB	40	86	0.6	>20
26	DOWT-F1	SCB	25	87	0.35	>20
27	DOWT-F2	SCB	25	87	0.35	>20
28	DOWT-TB	VCB	25	87	0.25	>20
29	JONE-F6	ACB	49	87	0.55	>20
30	JONE-F7	ACB	49	87	0.55	>20
31	GREW-F3	OCB		88	0	>20
32	SQUI-F4	SCB	26	88	0.35	>20
33	SPRY-T1	VCB	19	89	0.25	>20
34	BELL-T1	VCB	14	90	0.25	>20
35	SPRY-T2	VCB	12	90	0.25	>20
36	LIBN-F1	VCB	20	89	0	>20
37	EDGE-F1	VCB	22	90	0	>20
38	EDGE-F2	VCB	22	90	0	>20
39	PICB-F4	VCB	12	90	0	>20
40	SPRY-F4	VCB	12	90	0	>20
41	SPRY-F5	VCB	12	90	0	>20
42	SPRY-F1	VCB	19	90	0	>20
43	SPRY-F2	VCB	19	90	0	>20
44	EDGE-F3	OCB	52	90	0.2	>20
45	MONA-F4	ACB	38	90	0.35	>20
46	LIBN-T1	VCB		90	0.25	>20
47	NOTI-F4	SCB	21	91	0.35	>20
48	NOTI-T1	SCB	21	91	0.6	>20
49	SQUI-F1	SCB	26	91	0.35	>20
50	SIDN-F2	SCB	28	92	0.35	>20
51	GRER-F3	OCB		90	0	>20

Rank	Circuit Breaker Name	Type	Age	Health Index (%)	Criticality Multiple	Action Year from Today
52	GREW-F1	OCB		90	0	>20
53	SAND-F5	OCB	22	91	0	>20
54	SAND-F6	OCB	22	91	0	>20
55	NOTI-F1	SCB	21	93	0.35	>20
56	NOTI-F2	SCB	21	93	0.35	>20
57	UXBE-F1-K1	OCB	49	94	0.2	>20
58	UXBE-F2-K1	OCB	49	94	0.2	>20
59	JONE-T1	ACB	49	94	0.8	>20
60	JONE-F3	ACB	49	94	0.55	>20
61	RIVE-F1	OCB	49	94	0.2	>20
62	RIVE-F2	OCB	49	94	0.2	>20
63	RIVE-F3	OCB	49	94	0.2	>20
64	RIVE-F4	OCB	49	94	0.2	>20
65	RIVE-T1	OCB	49	94	0.2	>20
66	DOWT-T2-K2	VCB	16	94	0.25	>20
67	APPL-F1	SCB	23	94	0.35	>20
68	CVSC-F2	ACB	45	95	0.55	>20
69	CVSC-F3	ACB	45	95	0.55	>20
70	CVSC-F4	ACB	45	95	0.55	>20
71	DOWT-F3	VCB	16	94	0	>20
72	DOWT-F4	VCB	16	94	0	>20
73	MBDN-F1	OCB		95	0	>20
74	MBDN-F2	OCB		95	0	>20
75	TOWN-F1	ACB	41	95	0.35	>20
76	TOWN-F2	ACB	41	95	0.35	>20
77	EDGE-F4	OCB	52	95	0.2	>20
78	CVSC-T1	ACB	45	95	0.55	>20
79	CVSC-F1	ACB	45	95	0.55	>20
80	HERC-F3F4	ACB	38	96	0.55	>20
81	TOWN-TB	ACB	41	96	0.6	>20
82	TOWN-F4	ACB	40	96	0.6	>20
83	MONA-F3	ACB	38	96	0.35	>20
84	HERC-F1F2	ACB	38	96	0.55	>20
85	WESH-F1	ACB	32	97	0.35	>20
86	WESH-F2	ACB	32	97	0.35	>20
87	WESH-F3	ACB	32	97	0.35	>20
88	WESH-F4	ACB	32	97	0.35	>20
89	WESH-TB	ACB	32	97	0.6	>20

Rank	Circuit Breaker Name	Type	Age	Health Index (%)	Criticality Multiple	Action Year from Today
90	EDGE-T2	VCB	22	98	0.25	>20
91	SQUI-F2	SCB	26	98	0.35	>20
92	SQUI-T2	SCB	26	98	0.6	>20
93	BRAD-T1	VCB	20	98	0.25	>20
94	APPL-F4	SCB	23	98	0.35	>20
95	APPL-T1	SCB	23	98	0.6	>20
96	APPL-TB	SCB	23	98	0.6	>20
97	APPL-F2	SCB	23	99	0.35	>20
98	NOTI-F3	SCB	21	99	0.35	>20
99	PICB-TB	VCB	12	99	0.25	>20
100	MONA-F1	VCB	14	95	0	>20
101	BRAD-F1	VCB	20	98	0	>20
102	BRAD-F2	VCB	20	98	0	>20
103	BRAD-F3	VCB	20	98	0	>20
104	LIBN-F2	VCB	20	98	0	>20
105	LIBN-F3	VCB	20	98	0	>20
106	FBDR-F1	OCB	22	98	0	>20
107	FBDR-F2	OCB	22	98	0	>20
108	FBDR-F3	OCB	22	98	0	>20
109	BAYR-F1	OCB	22	99	0	>20
110	SAND-F1	OCB	22	99	0	>20
111	SAND-F2	OCB	22	99	0	>20
112	BAYR-F2	OCB	22	99	0	>20
113	BAYR-F3	OCB	22	99	0	>20
114	PICB-T1	VCB	12	99	0.25	>20
115	PICB-T2	VCB	12	99	0.25	>20
116	DOWT-T2-K1	SCB		100	0.6	>20
117	44-R2L	OCB		100	0.25	>20
118	44-ABL	OCB		100	0.25	>20
119	JONE-T	OCB		100	0.2	>20
120	MONA-F2	VCB	14	99	0	>20
121	BELL-F1	VCB	14	99	0	>20
122	BELL-F2	VCB	14	99	0	>20
123	PICB-F1	VCB	12	99	0	>20
124	PICB-F2	VCB	12	99	0	>20
125	PICB-F3	VCB	12	99	0	>20
126	PICB-F5	VCB	12	99	0	>20
127	PICB-F6	VCB	12	99	0	>20

Rank	Circuit Breaker Name	Type	Age	Health Index (%)	Criticality Multiple	Action Year from Today
128	JBHE-F1-K2	OCB		100	0	>20
129	JBHE-F2-K2	OCB		100	0	>20
130	REID-F1	SCB			0	
131	REID-F2	SCB			0	
132	BEAW-F1	ACB			0	
133	BEAW-F2	ACB			0	
134	LBDD-F1	OCB			0	
135	LBDD-F2	OCB			0	
136	JBHE-F1-K1	OCB			0	
137	JBHE-F2-K1	OCB			0	
138	JBHE-F3	OCB			0	
139	JBHE-F4	OCB			0	
140	SHUT-F1	OCB			0	
141	SHUT-F2	OCB			0	

2.6 Substation Breakers Data Analysis

The data available for Substation Breakers includes age, inspection results, on-site test results, and overall performance estimate.

2.6.1 Substation Breakers Data Availability Distribution

The average DAI for Substation Breakers is 57%. The data availability distribution for the population is shown in Figure 2-6.

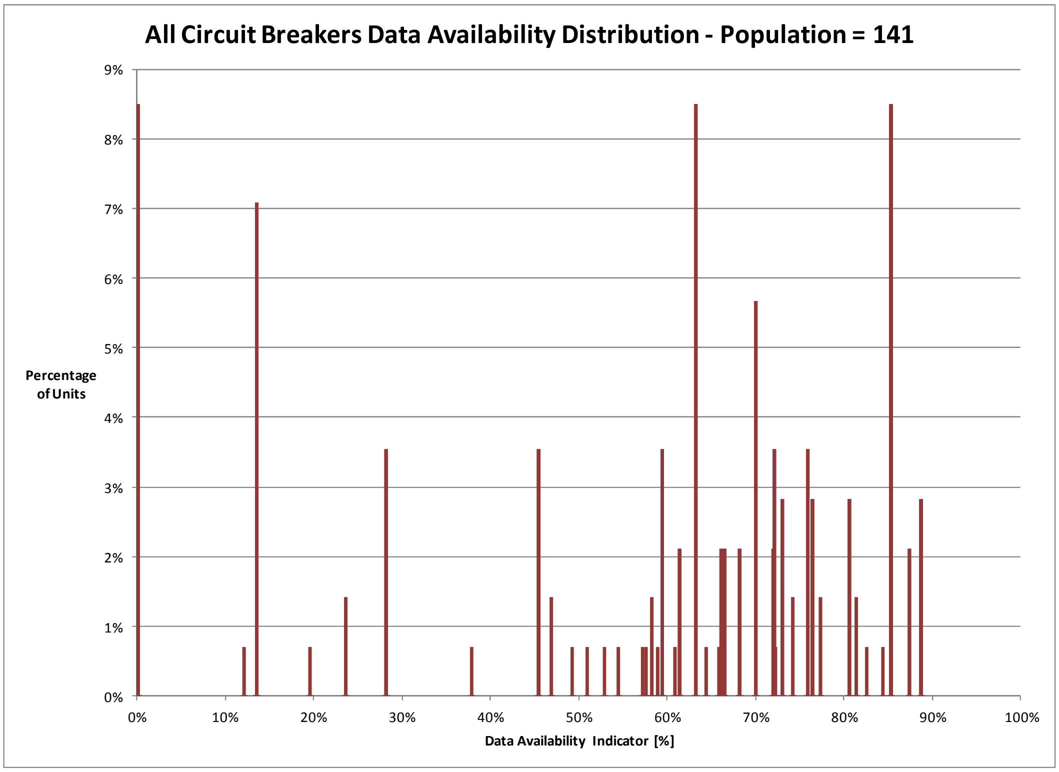

Figure 2-6 Substation Breakers Data Availability Distribution

2.6.2 Substation Breakers Data Gap

For this asset category, the major data gap is that inspection records are not at unit level. To better assess the condition of individual units, such data should be recorded for each individual unit.

Additional data gaps are as follows:

Table 2-15 Substation Breakers Data Gaps

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
CB timing	Contact performance	☆☆☆	CB operating mechanism	Opening/closing function	On-site test
Bushing Power Factor	Insulation	☆☆	CB HV grading capacitor	HV insulation	On-site test
Oil quality	Arc extinction	☆☆	OCB oil	Arc extinction feature of OCB oil	On-site Sampling, Lab test
Dew point	Arc extinction	☆☆	SF6 gas	Arc extinction feature of SCB gas	On-site test
Fault operation counter	Service record	☆☆	CB operation	Number of operation at faults	Service record

3 Wood Poles

Wood poles are used to support primary distribution lines at voltages from 4.16 kV to 44 kV. The wood species commonly used for distribution wood poles predominantly include Red Pine, Jack Pine and Western Red Cedar (WRC), either butt-treated or full-length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used.

Distribution line design standards dictate usage of poles of varying height and strength, depending upon the number and size of conductors, the average length of adjacent spans, maximum loadings, line angles, appropriate loading factors and the mass of installed equipment. Poles are categorized into Classes (1 to 7) which reflect the relative strength of the pole. Stronger poles (lower numbered classes) are used for supporting equipment and handling stresses associated with corner structures and directional changes in the line. The height of a pole is determined by a number of factors, such as the number of conductors it must support, equipment-mounting requirements, clearances below the conductors for roads and the presence of coaxial cable and/or other telecommunications facilities.

3.1 Wood Poles Degradation Mechanism

Since wood is a natural material, the degradation processes are somewhat different to those which affect other physical assets on electricity distribution systems. The critical processes are biological involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Certain species of fungi are known to attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot. As the decay processes requires the presence of water and oxygen, the area of the pole most susceptible to degradation is at and around the ground line or at the top of the pole. Although it is possible in some circumstances for decay to occur in other locations, it is normal to concentrate inspection and assessment of poles in the most critical areas. In addition to the natural degradation processes, external damage to the pole by wildlife can also be a significant problem. Examples may include attack by termites, small mammals or woodpeckers.

To prevent attack and decay, wood poles are treated with preservatives prior to being installed. The preservatives have two functions; firstly, to keep out moisture vital to fungal attacks, and, secondly, as a biocide to kill off fungus spores. As wood pole use has evolved in the electricity industry, the nature of the preservatives used to treat the wood has also evolved, as the chemicals used previously have become unacceptable from an environmental viewpoint. Preservative treatments applied to poles prior to 1980 range from none on some WRC poles, to butt-treated and full-length Creosote or Pentachlorophenol (PENTA) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution).

As a structural item, the sole concern when assessing the condition of a wood pole is the native reduction in mechanical strength due to degradation or damage. A particular problem when assessing wood poles is the potentially large variation in their original mechanical properties. Depending on the species, the mechanical strength of a new wood pole can vary greatly. Typically, the first standard deviation has a width of ±15% for poles nominally in the same class. However, in some test programs, the minimum measured strength has been as low as 50% of the average.

Assessment techniques start with simple visual inspection of poles. This is often accompanied by basic physical tests such as prodding tests and hammer tests to detect evidence of internal decay. Over the past 20 years, electricity companies have sought more objective and accurate means of determining condition and estimating remaining life. This has led to the development of a wide range of condition assessment and diagnostic tools and techniques for wood poles. These include techniques that are designed to apply the traditional probing or hammer tests in a more controlled, repeatable and objective manner. Devices are available that measure the resistance of a pin fired into the pole to determine the severity of external rot and instrumented hammers that record and analyze the vibration caused by a hammer blow to identify patterns that indicate the presence of decay. Direct assessment of condition by using a decay resistance drill or an auger to extract a sample through the pole, are also widely used. Indirect techniques, ultrasonic, X-rays, electrical resistance measurement have also been widely used.

Although wood pole condition assessment is driven by the condition of the wood pole itself, replacement of the ancillary components, foundations, cross-arms, guys, anchors and insulators may also be required. The poles, foundations and cross-arms support the required insulators and phase conductors. The guys and anchors maintain the mechanical integrity of the structure and the insulators electrically insulate the conductors from ground potential.

There are many factors considered by utilities when establishing condition for wood poles. These include species of wood, historic rates of decay and average lifetimes, environment, perceived effectiveness of available techniques and cost. However, perhaps the most significant is the policy of routine line inspections. A foot patrol of overhead lines undertaken on a regular cycle is extremely effective in addressing the required safety and security obligations.

Consequences of an in-service pole failure are quite serious, as they could lead to a serious accident involving the public. Depending on the number of circuits supported, a pole failure may also lead to a power interruption for a significant number of customers.

3.2 Wood Poles Health Index Formulation

This section presents the Health Index Formula that was developed and used for VC Wood Poles. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

3.2.1 Wood Poles Condition and Sub-Condition Parameters

Table 3-1 Wood Poles Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	CPS Lookup Table
1	Pole Strength	5	Table 3-2
2	Physical Condition	4	Table 3-3
3	Auxiliary Accessories	1	Table 3-4
4	Service Record	3	Table 3-5

Table 3-2 Wood Pole Strength (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Pole Strength	Table 3-9	1	4

Table 3-3 Wood Poles Physical Condition (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Pole top feathering	Table 3-6	1	4
2	Surface rot above/below GL	Table 3-6	2	4
3	Internal decay/decay pockets at GL	Table 3-6	2	4
4	Carpenter ants damage/WP Hole	Table 3-6	2	4
5	Fire/mechanical damage	Table 3-6	3	4
6	Cracks /Crack to GL	Table 3-6	1	4

Table 3-4 Wood Poles Auxiliary Accessories (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Cross arm rot	Table 3-6	3	4
2	Slack guy wire	Table 3-7	2	4
3	Slack/broken ground wire	Table 3-7	1	4
4	Pole leaning/bend in pole	Table 3-7	8	4

Table 3-5 Wood Poles Service Record (m=4) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Age	Figure 3-1	1	4
2	Overall condition	Table 3-8	2	4

3.2.2 Wood Poles Condition Parameter Criteria

Visual Inspection

--- Inspection count 1

Table 3-6 Wood Poles Inspection Count 1 Condition Criteria

CPF	Description
4	0
3	1
2	2
1	3
0	4

Where inspection count is calculated based on detection of specific defects as below:

Year	Score			Weight
	1	2	4	
2012	Slight defect	Moderate defect	Extensive defect	1
2011				0.9
2010				0.8
2009				0.7
2008				0.6

Inspection count = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

Where i refers to the year the CM was issued

--- Inspection count 2

Table 3-7 Wood Poles Inspection Count 2 Condition Criteria

CPF	Description
4	0
3	1
2	2
1	3
0	4

Where inspection count is calculated based on detection of specific defects as below:

Year	Score		Weight
	0	4	
2012	Defect not found	Defect found	1
2011			0.9
2010			0.8
2009			0.7
2008			0.6

Inspection count = $\frac{\sum Score_i \times Weight_i}{\sum Weight}$

Where i refers to the year the CM was issued

Overall Condition

Table 3-8 Wood Poles Overall Condition Criteria

CPF	Description (Overall count)
4	0
3	1
2	2
1	3
0	4

Where overall count is calculated based on overall condition as below:

Year	Score				Weight
	0	2	3	4	
2012	Good	Fair	Fair-Poor	Poor	1
2011					0.9
2010					0.8
2009					0.7
2008					0.6

Overall count = $MAX(Score_i \times Weight_i)$

Where i refers to the year the inspection was conducted

Pole Strength

Table 3-9 Pole Strength Condition Criteria

CPF	Description (percentage of original strength at installation)
4	90
3	75
2	66
1	33
0	0

Where strength percentage = measured fibre strength/design fibre strength. The design fibre strength ratings for different species are listed below.

Pole species	Design Fibre Strength (psi)
Pine	8000
Southern Pine (SP)	8000
Jack Pine (JP)	6600
Cedar	6600
Western Red Cedar (WC)	6600
Douglas Fir (DF)	8000

Age

Assume that the failure rate for Wood Poles exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 40 and 65 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age for wood poles is also shown in the figure below:

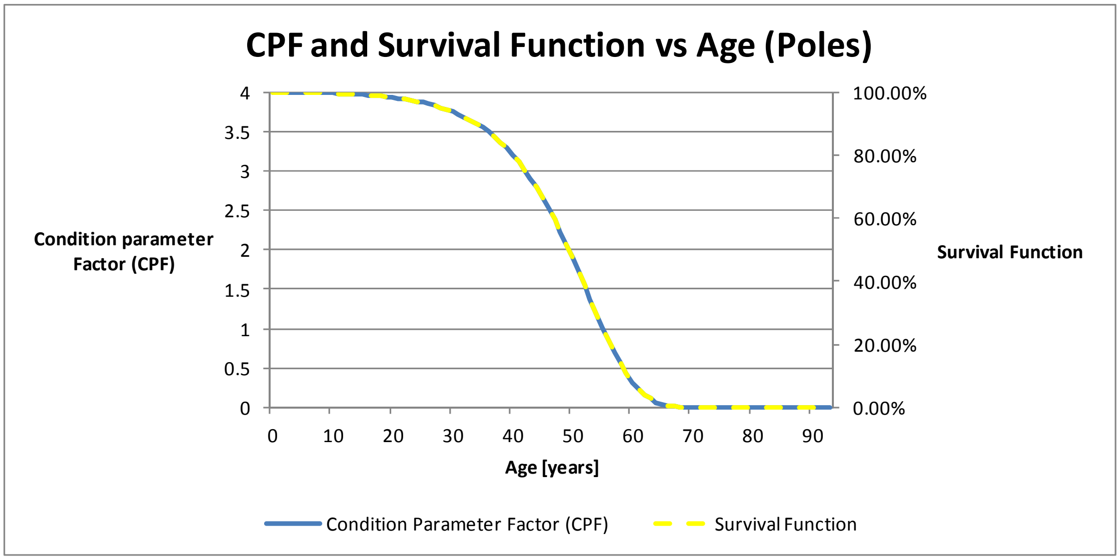

Figure 3-1 Wood Pole Age Condition Criteria (Wood Poles)

3.3 Wood Poles Age Distribution

The age distribution is shown in the figure below. Age was available for only for a small sample representing only about 6% of the entire population For this sample average age was found to be 28 years.

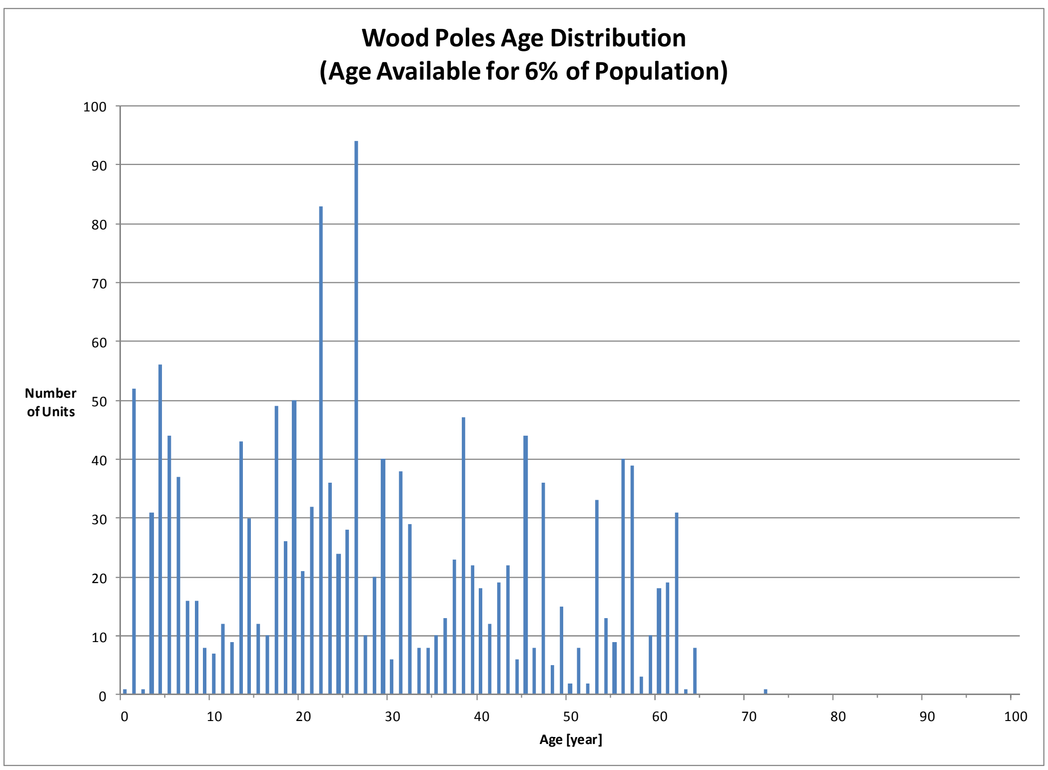

Figure 3-2 Wood Poles Age Distribution

3.4 Wood Poles Health Index Results

There are 28000 in-service Wood Poles at VC. Only 1538 of them have data. It is assumed that the absence of an entry in the inspection database implies that the status of a unit is defect free. On that basis, all the units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 87%. Approximately 1.8% of the units were found to be in poor or very poor condition.

The Health Index Results are as follows:

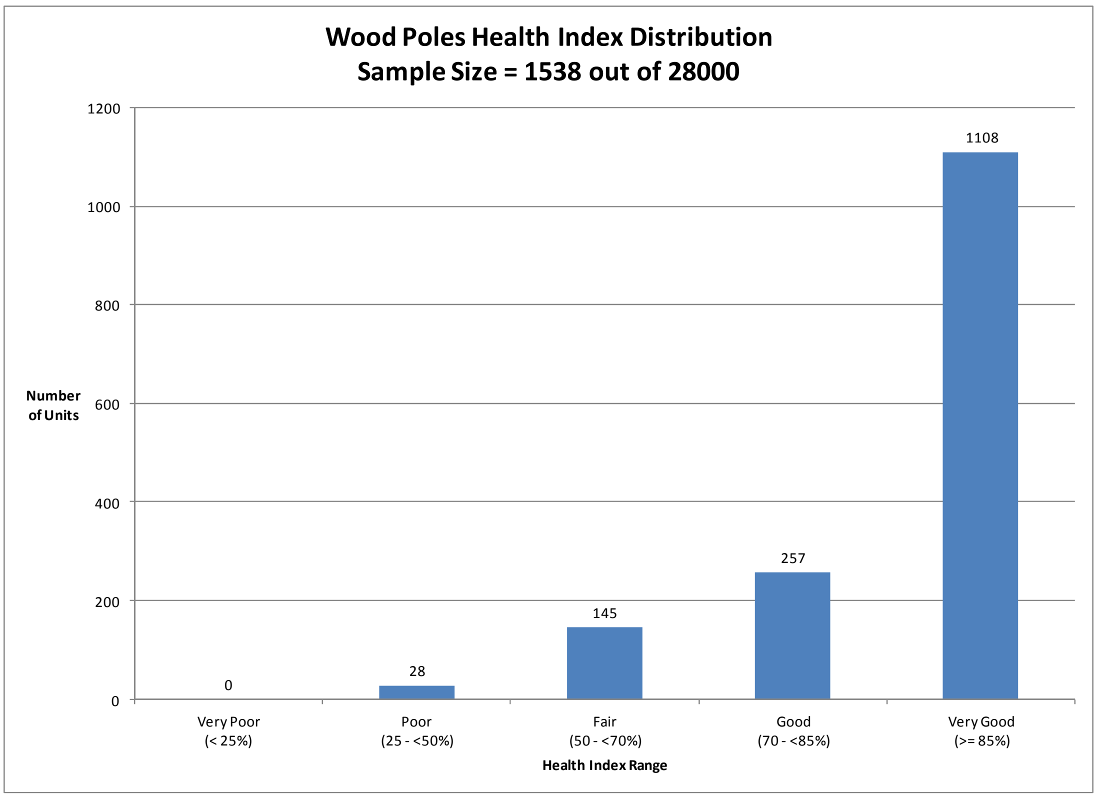

Figure 3-3 Wood Poles Health Index Distribution (Number of Units)

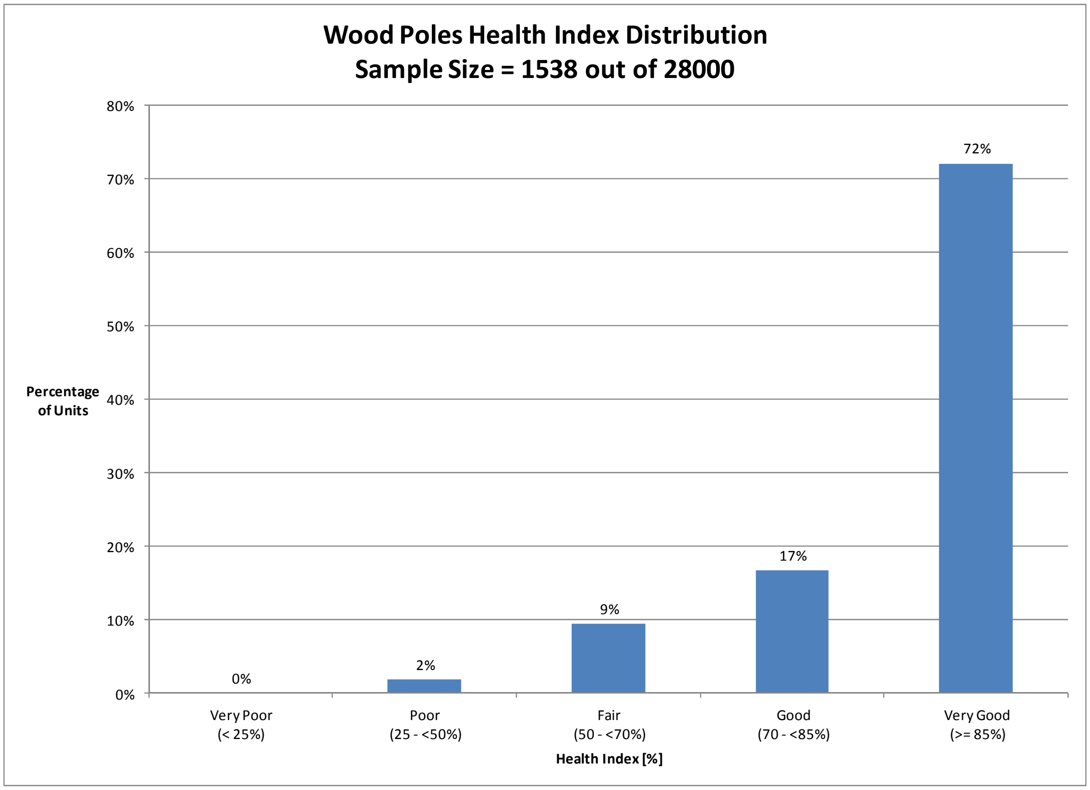

Figure 3-4 Wood Poles Health Index Distribution (Percentage of Units)

3.5 Wood Poles Condition-Based Flagged-For-Action Plan

As it is assumed that Wood Poles are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate f(t), as described in Section II.2.2. This means the Flagged-For-Action Plan is based on the number of expected failures in a given year.

Given the small sample size in this project, the flagged-for-action plan is extrapolated to the total population of wood poles.

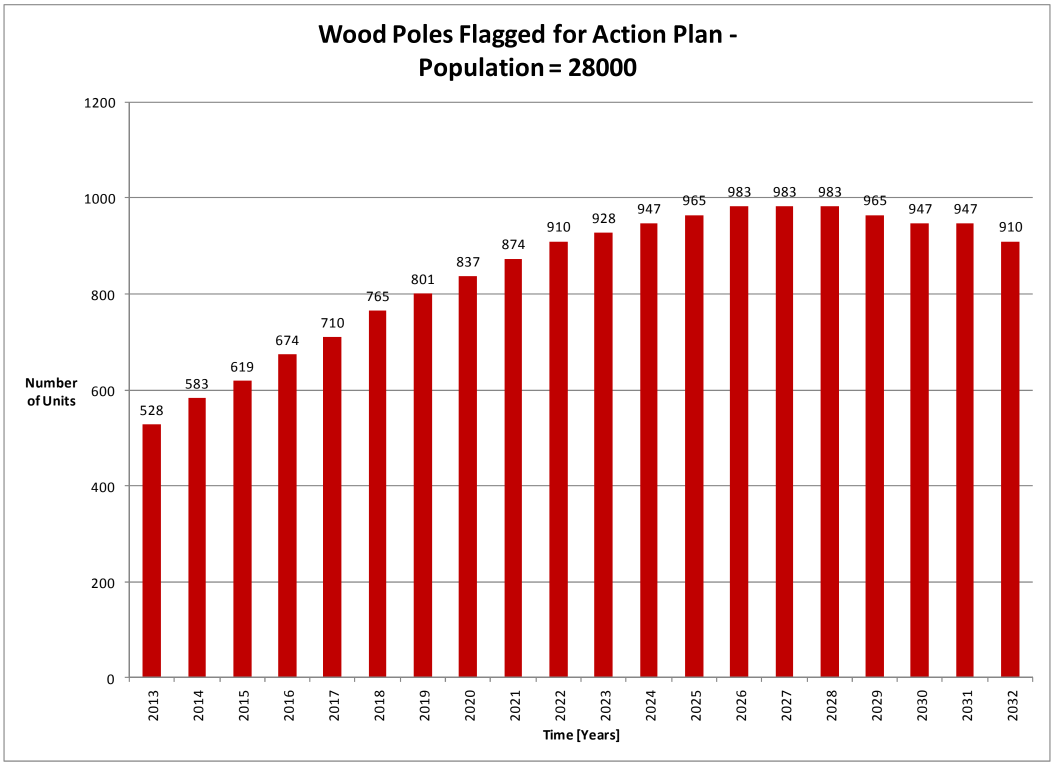

Figure 3-5 Wood Poles Condition-Based Flagged-For-Action Plan

3.6 Wood Poles Data Analysis

The data available for Wood Poles includes age, inspections, pole strength test data.

3.6.1 Wood Poles Data Availability Distribution

Inspection information was taken from VC's access database. If no entry was found for an asset, it was assumed that there is no sufficient information on the status of the unit, and the assessment has to rely on its physical age. If however no entry was found for a parameter, it was assumed that such a parameter has no issue, thus being in good status.

The average DAI for Wood Poles is 98.0% for the sampled wood poles.

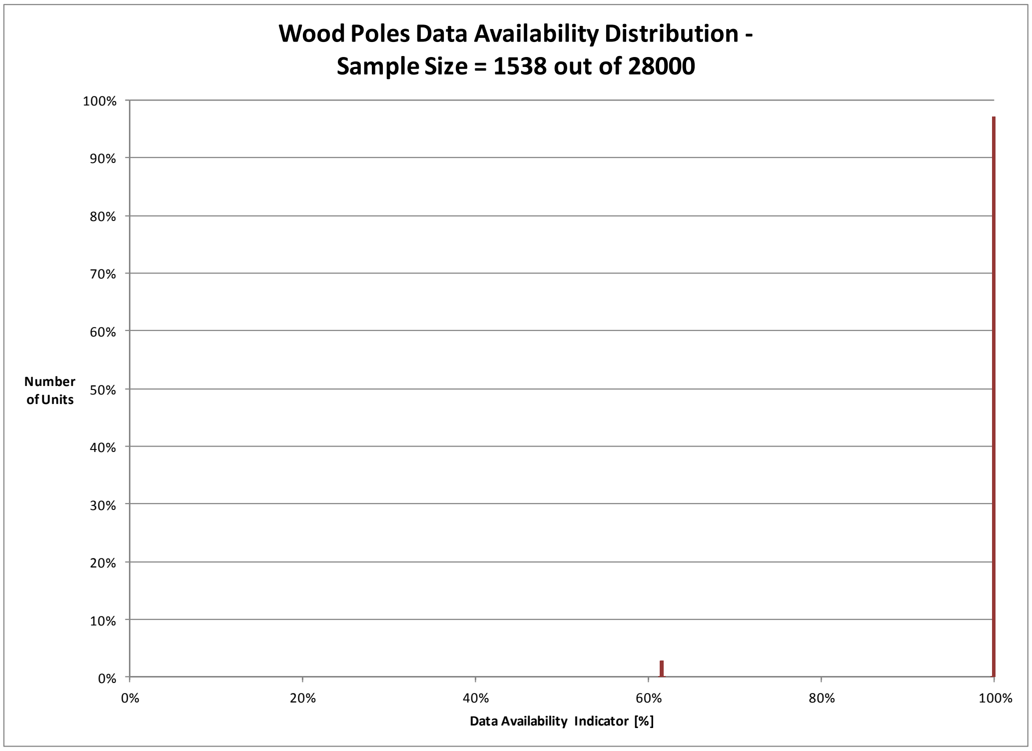

Figure 3-6 Wood Poles Data Availability Distribution

3.6.2 Wood Poles Data Gap

In this asset group, much of the required data have been incorporated into the Health Index formula. There is no major data gap for the sampled wood poles.

However, such information is available for only a very small percentage of the entire population. It is recommended that VC collect and store information for more wood poles in VC's system.

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4 Pole Top Transformers

Pole-mounted distribution transformers convert power from the distribution primary line voltage to the 600/347 V or 120/240V utilization voltage employed by the customer. Single-phase pole-mounted transformers are commonly available in ratings from 5kVA to 167kVA but can be as high as 500kVA. They are available in voltages from 4.16/2.4kV to 34.5/19kV. Pole-mounted transformers are generally contained in cylindrical cans filled with insulating oil. The connection to the high voltage source is via a bushing, usually on the top of the unit. The transformer core is generally a wrapped sheet-type steel. Wound copper high voltage windings and sheet-type low voltage windings are wound concentrically on the core. Distribution transformers are self-cooled by air and occasionally have external cooling fins. Typically, pole-mounted transformers of size 100kVA and below are attached directly to the pole whereas higher ratings are mounted on cross-beams.

4.1 Pole Top Transformers Degradation Mechanism

Degradation of pole top transformers can occur due to the following mechanisms:

- Corrosion of the tank
- Deterioration or breakage of the bushings
- Deterioration of internal switching or fusing devices
- Degradation of internal insulating material
- Degradation of oil

Tank corrosion can be problematic for overhead transformers particularly in areas of high contamination. Porcelain bushings can develop mechanical cracks or can be subject to breakage due to mechanical vibration and forces. Deterioration of the pole-mounted transformer can also be due to problems such as: breakage of switches and leakage of under-oil fuses.

The life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life. Insulation condition can also be affected by voltage and current surges.

Distribution pole-mounted transformers sometimes require replacement because of non-condition related factors such as customer load growth, pole replacement or road widening. If a transformer is simply overloaded, a decision is required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost-benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent-sized new transformer, labour cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

Visual inspections provide considerable information on transformer asset condition. Leaks, rusting, and deteriorated connectors can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

The consequences of distribution transformer degradation can be severe if it results in an eventful failure. Though rare, pole-mounted transformers can fail with sufficient energy release to rupture the tank and release oil into the surrounding environment.

4.2 Pole Top Transformers Health Index Formulation

This section presents the Health Index Formula that was developed and used for VC Pole Top Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

4.2.1 Pole Top Transformers Condition and Sub-Condition Parameters

Given the fact that very few Pole Top Transformers have information other than age, in this study only age data are used for Health Index study.

Table 4-1 Pole Top Transformers Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	CPS Lookup Table
1	Service Record	1	Table 4-2

Table 4-2 Pole Top Transformers Service Record (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Age	Figure 4-1	1	4

4.2.2 Pole Top Transformers Condition Parameter Criteria

<u>Age</u>

Assume that the failure rate for Pole Top Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - \ P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 40 and 65 years the probability of failure (P_f) for this asset are 10% and 99% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

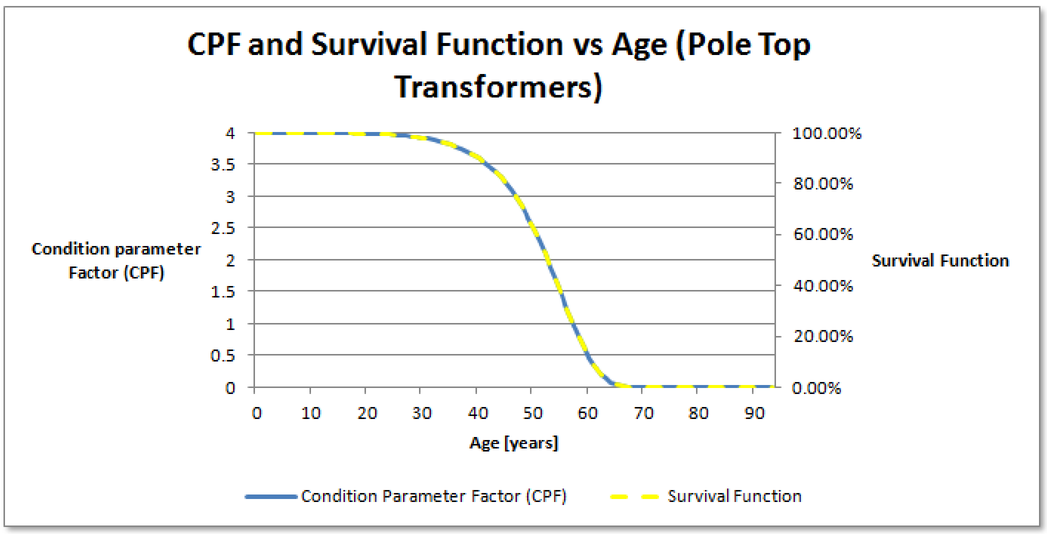

Figure 4-1 Age Condition Criteria (Pole Top Transformers)

4.3 Pole Top Transformers Age Distribution

The age distribution is shown in the figure below. Age was available for 49% of the population. The average age was found to be 24 years.

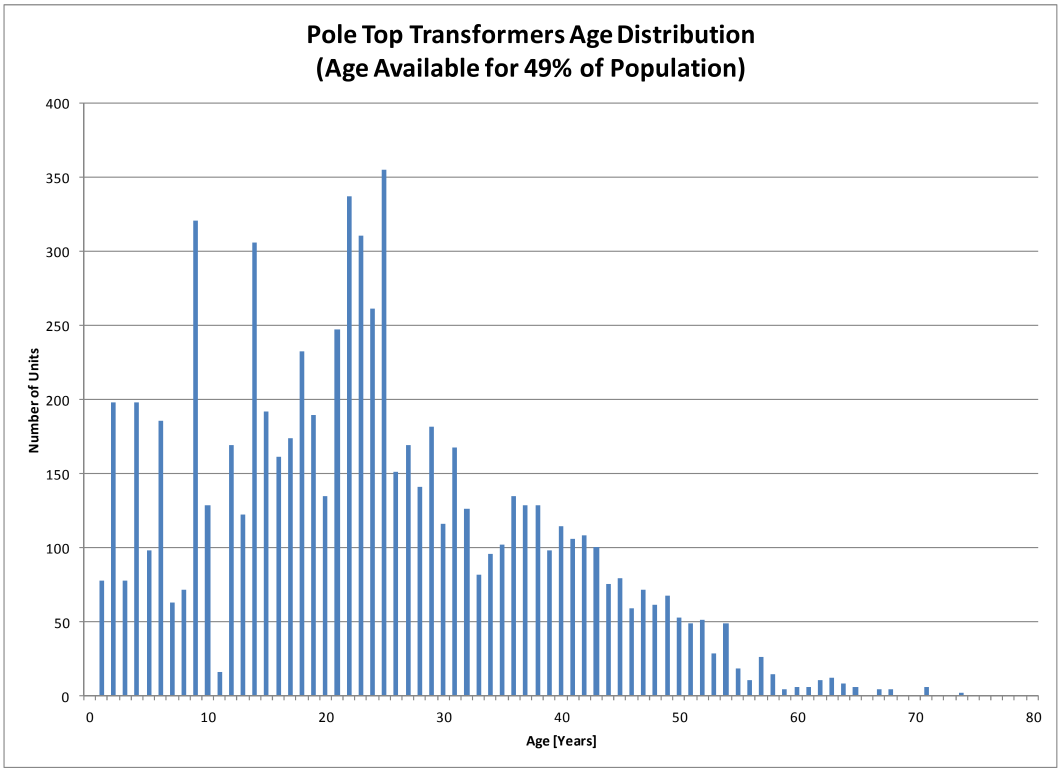

Figure 4-2 Pole Top Transformers Age Distribution

4.4 Pole Top Transformers Health Index Results

There are 7661 in-service Pole Top Transformers at VC.

The average Health Index for this asset group is 94%. Approximately 2.8% of the units were found to be in poor or very poor condition.

The Health Index Results are as follows:

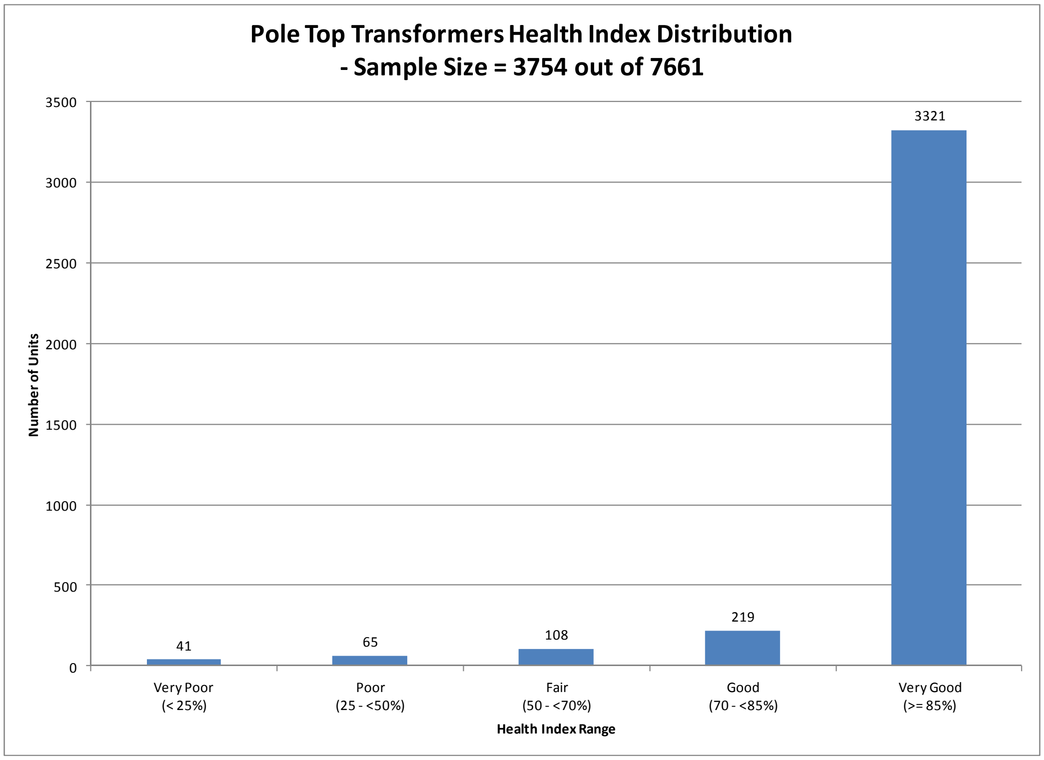

Figure 4-3 Pole Top Transformers Health Index Distribution (Number of Units)

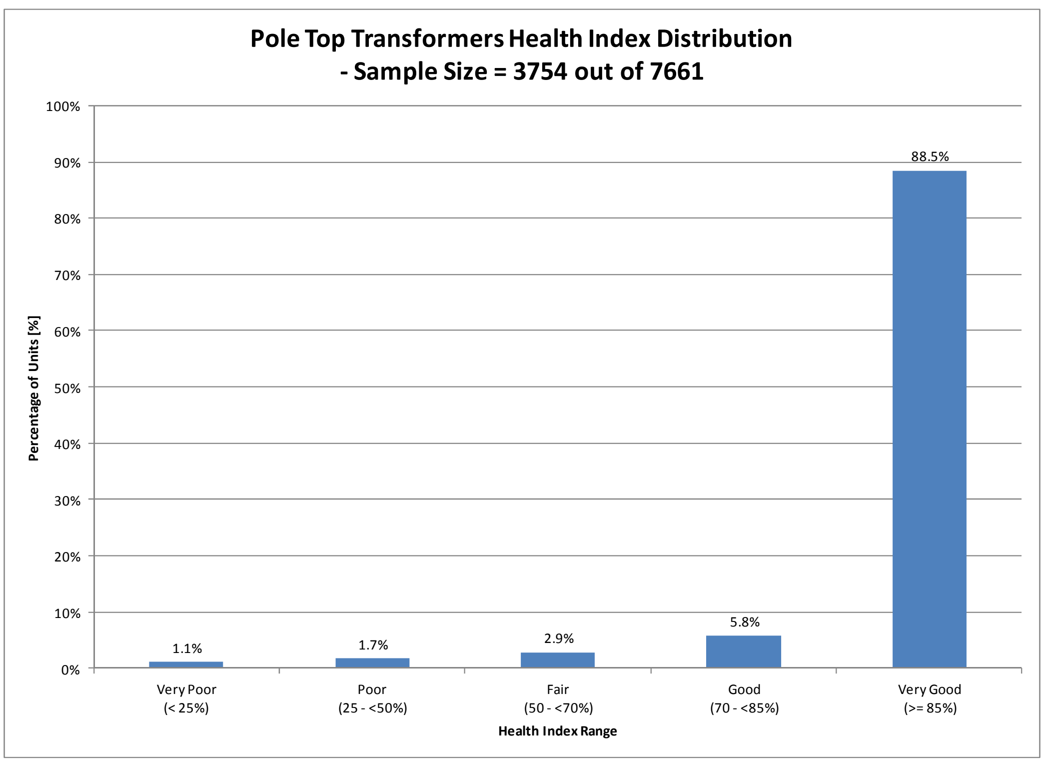

Figure 4-4 Pole Top Transformers Health Index Distribution (Percentage of Units)

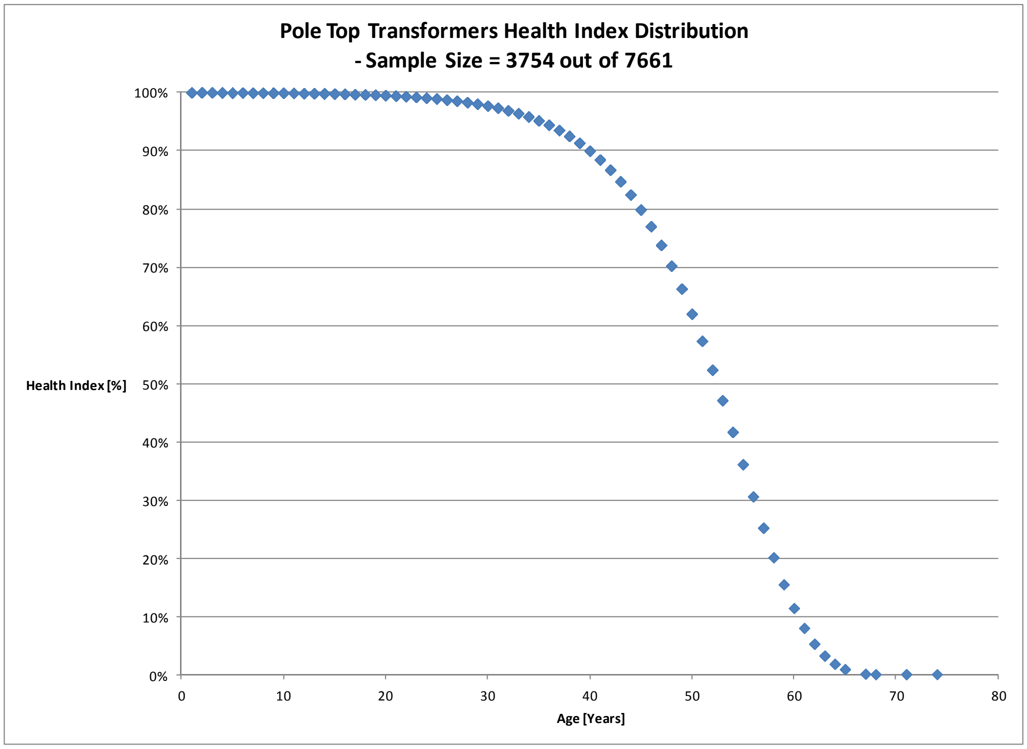

Figure 4-5 Pole Top Transformers Health Index vs Age

4.5 Pole Top Transformers Condition-Based Flagged-For-Action Plan

As it is assumed that Pole Top Transformers are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate f(t), as described in Section II.2.2. That means the Flagged-For-Action Plan is based on the number of expected failures in a given year.

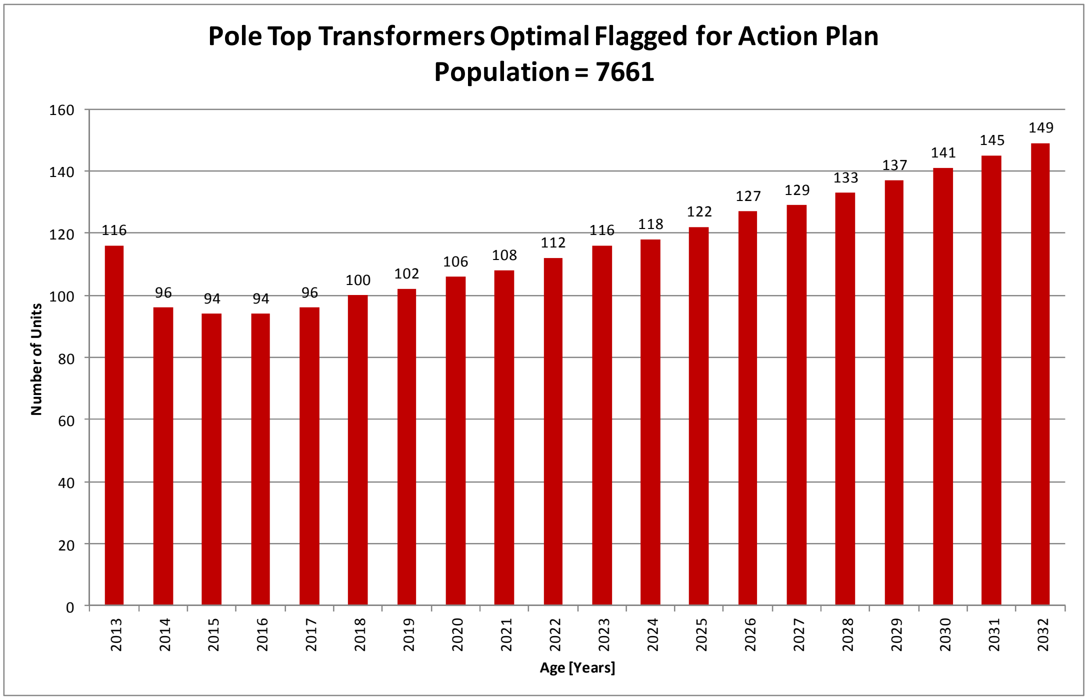

Figure 4-6 Pole Top Transformers Condition-Based Flagged-For-Action Plan

4.6 Pole Top Transformers Data Analysis

The data available for Pole Top Transformers includes age, and very limited inspection results.

4.6.1 Pole Top Transformers Data Availability Distribution

Inspection information was taken from VC's asset management database. If no entry was found for an asset, it was assumed that there is no sufficient information on the status of the unit, and the assessment has to rely on its physical age. If however no entry was found for a parameter, it was assumed that such a parameter has no issue, thus being in good status.

The average DAI for Pole Top Transformers is 19%, as the sample size comprises less than half of the population.

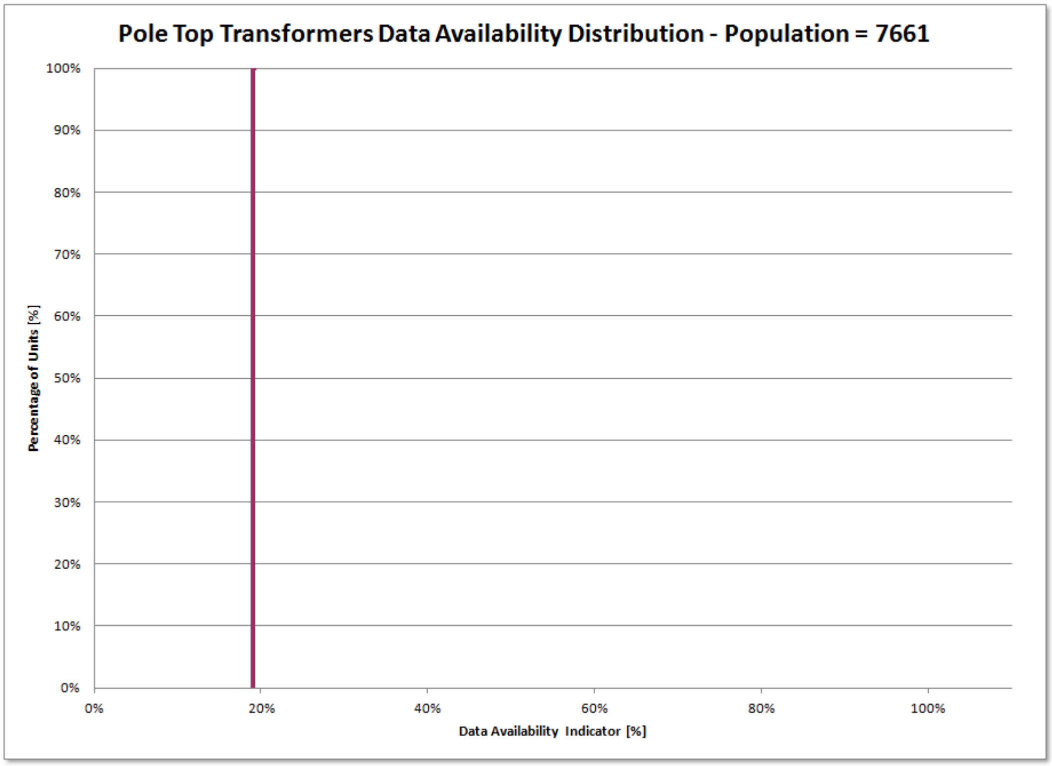

Figure 4-7 Pole Top Transformers Data Availability Distribution

4.6.2 Pole Top Transformers Data Gap

In this asset group, very few units have inspection data. For future ACA study, VC's inspection maintenance records need to be stored in asset management even if no defect is found. This is because the condition assessment heavily relies on the historic trend of such records.

The helpful data that can be collected are:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Oil leak	Connection & Insulation	☆ ☆	Transformer	Findings at routine inspection	Foot patrol inspection
Bushing		☆ ☆	Transformer	Findings at routine inspection	Foot patrol inspection
Connection Hot Spot		☆	Transformer connection	Findings at routine inspection	IR scan
Tank exterior issue	Physical Condition	☆	Transformer tank	Findings at routine inspection	Foot patrol inspection
Overall*	Service Record	☆	Transformer	General status evaluation based on routine operation and inspection	Operation Record
Loading		☆ ☆	Transformer load	Monthly 15 min peak load throughout years	Operation Record

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5 Overhead Line Switches

The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements. Disconnect switches are relatively simple in design compared to circuit breakers, since they are not typically required to interrupt fault current.

In general, line switches consist of mechanically movable copper blades supported on insulators and mounted on metal bases. Their operating mechanism can be either a simple hook stick or a manually driven mechanical mechanism to move the ganged contacts. Air serves as the insulating medium between contacts when these switches are in the open position. Air break switches must have the capability of providing visual confirmation of the open/close position. Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with switch handle locked in open position.

Most distribution line switches are rated 600 A continuous rating. While some categories of the switches are rated for load interruption, others are designed to operate under no load conditions. Non-load break switches operate only when the current through the switch is zero. When used in conjunction with cutout fuses, switches provide short circuit interruption rating.

5.1 Overhead Line Switches Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment, which may result in excessive arcing during operation
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out the switch operating mechanism may seize making the disconnect switch inoperable. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

The condition assessment of overhead switches involves visual inspections which would reveal the extent of wear or corrosion on main contacts, condition of stand-off insulators and operating mechanism. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective tests to locate hot spots.

Consequences of overhead line switch failure may include customer interruption and health and safety consequences for operators.

5.2 Overhead Line Switches Health Index Formulation

This section presents the Health Index Formula that was developed and used for VC Overhead Line Switches. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

5.2.1 Overhead Line Switches Condition and Sub-Condition Parameters

Table 5-1 Overhead Line Switches Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	CPS Lookup Table
1	Operating Mechanism	5	Table 5-2
2	Insulation & Connection	2	Table **5-3**
3	Service Record	2	Table 5-4

Table 5-2 Overhead Line Switches Operating Mechanism (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Maintenance required on mechanical operation	Table 5-5	2	4
2	Maintenance required on blade movement contact	Table 5-5	1	4
3	Maintenance required on lubrication	Table 5-5	1	4

Table 5-3 Overhead Line Switches Insulation & Connection (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Insulator condition	Table 5-6	2	4
2	Maintenance required on Electrical connection	Table 5-5	1	4
3	grounding	Table 5-7	1	4

Table 5-4 Overhead Line Switches Service Record (m=4) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Overall	Table 5-8	2	4
2	Age	Figure 9-1	1	4

5.2.2 Condition Parameter Criteria

Visual Inspections

Table 5-5 Maintenance Count Condition Criteria

Condition Rating*	CPF	Description
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where inspection count is calculated based on detection of specific defects as below:

Year	Score		Weight
	0	4	
2012	No	Yes	1
2011			0.9
2010			0.8
2009			0.7
2008			0.6

Inspection count = $\sum Score_i \times Weight_i$

Where i refers to the year the inspection was conducted

Table 5-6 Inspection Count Condition Criteria

Condition Rating	CPF	Description
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where inspection count is calculated based on Veridian Inspection Database as below:

Year	Score				Weight
	OK	FIXED	Monitored	Fix	
2012	0	1	2	4	1
2011					0.9
2010					0.8
2009					0.7
2008					0.6

Inspection count = $\sum Score_i \times Weight_i$

Where i refers to the year the inspection was conducted

Measurement

Table 5-7 Grounding Resistance Condition Criteria

Condition Rating*	CPF	Description	
		Measurement (Ohm)	Inspection (When measurement unavailable)
A	4	0	good
B	3	20	ok
C	2	25	
D	1	30	
E	0	>30	

Overall Condition

Table 5-8 Overall Condition Criteria

Condition Rating*	CPF	Description
A	4	0
B	3	3
C	2	6
D	1	9
E	0	12

Where overall count is calculated based on total sum of VC's Action Required after each inspection as below:

Year	Score 0	Score 4	Weight
2012	NO	YES	1
2011			0.9
2010			0.8
2009			0.7
2008			0.6

Inspection count = $\sum Score_i \times Weight_i$

Where i refers to the year the maintenance was conducted

Age

Assume that the failure rate for Overhead Line Switches exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 20 and 30 years the probability of failure (P_f) for this asset are 20% and 90% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age for overhead line switches is also shown in the figure below:

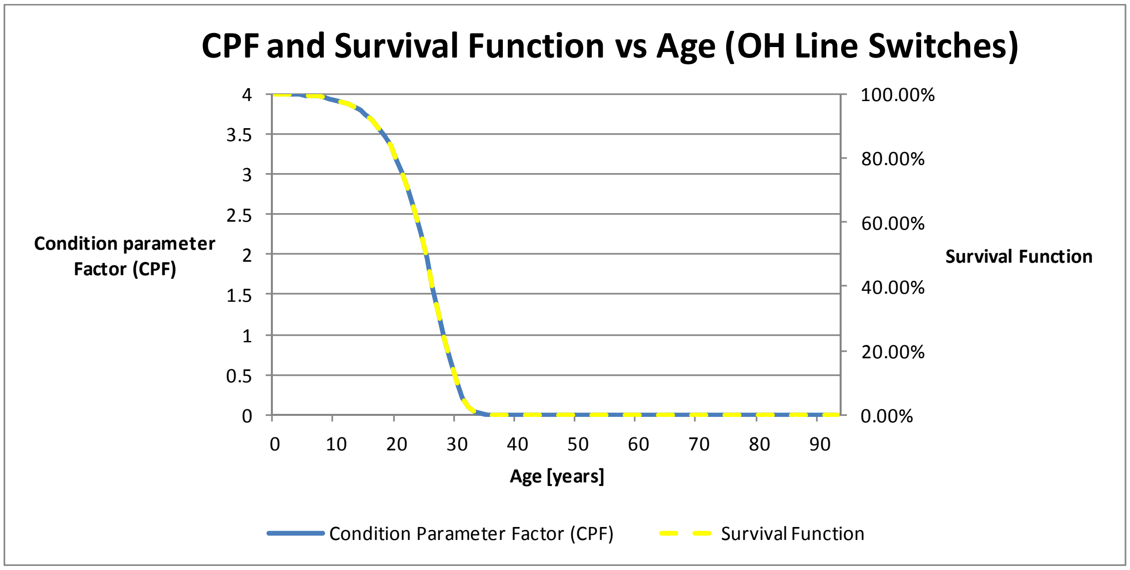

Figure 5-1 Overhead Line Switches Age Condition Criteria (Overhead Line Switches)

5.3 Overhead Line Switches Age Distribution

The age distribution is shown in the figure below. Age was available for 19% of the population. The average age was found to be 9 years.

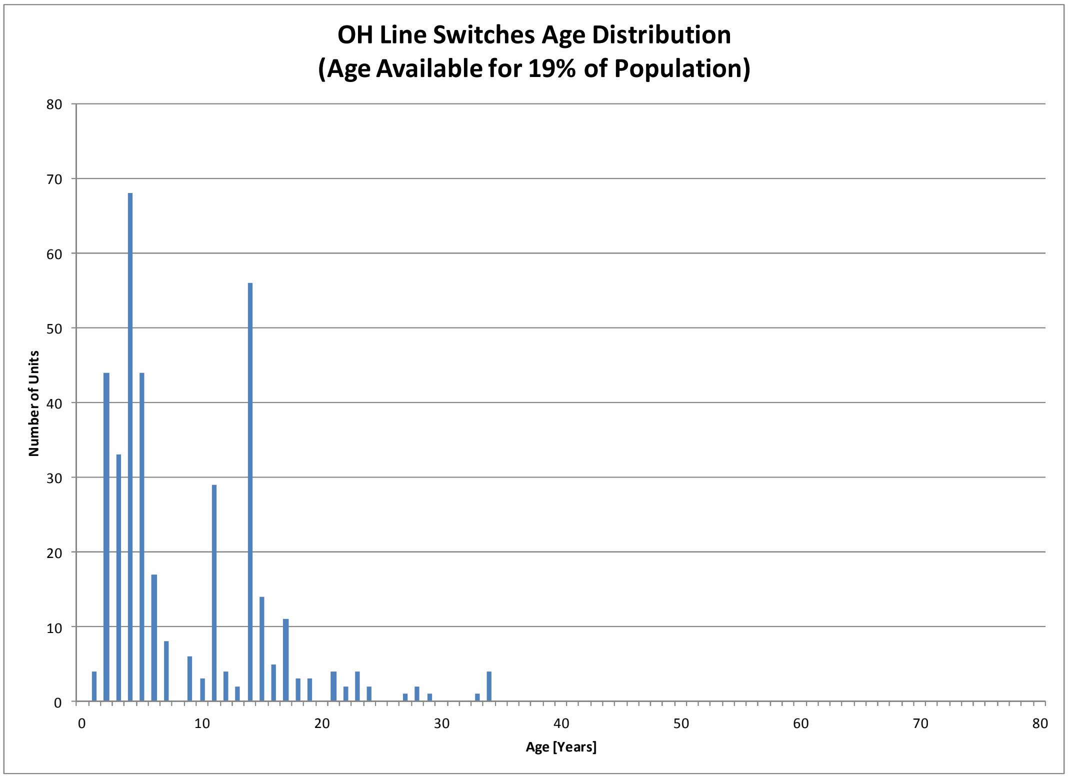

Figure 5-2 Overhead Line Switches Age Distribution

5.4 Overhead Line Switches Health Index Results

In this study, only 3-phase gang-operated Overhead Line Switches are addressed. There are 1968 such switches in service at VC. It is assumed that the absence of an entry in the inspection database implies that the status of a unit is unknown. On that basis, 80% units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 66%. Approximately 34.8% of the units were found to be in poor or very poor condition.

The Health Index Results are as follows:

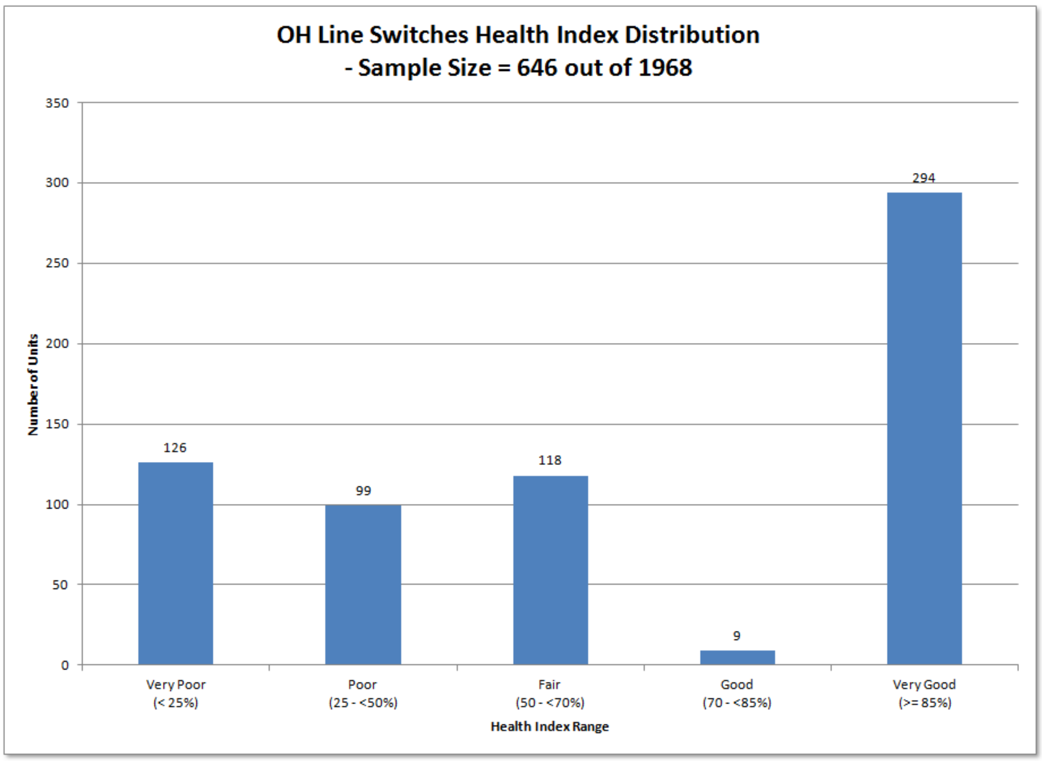

Figure 5-3 Overhead Line Switches Health Index Distribution (Number of Units)

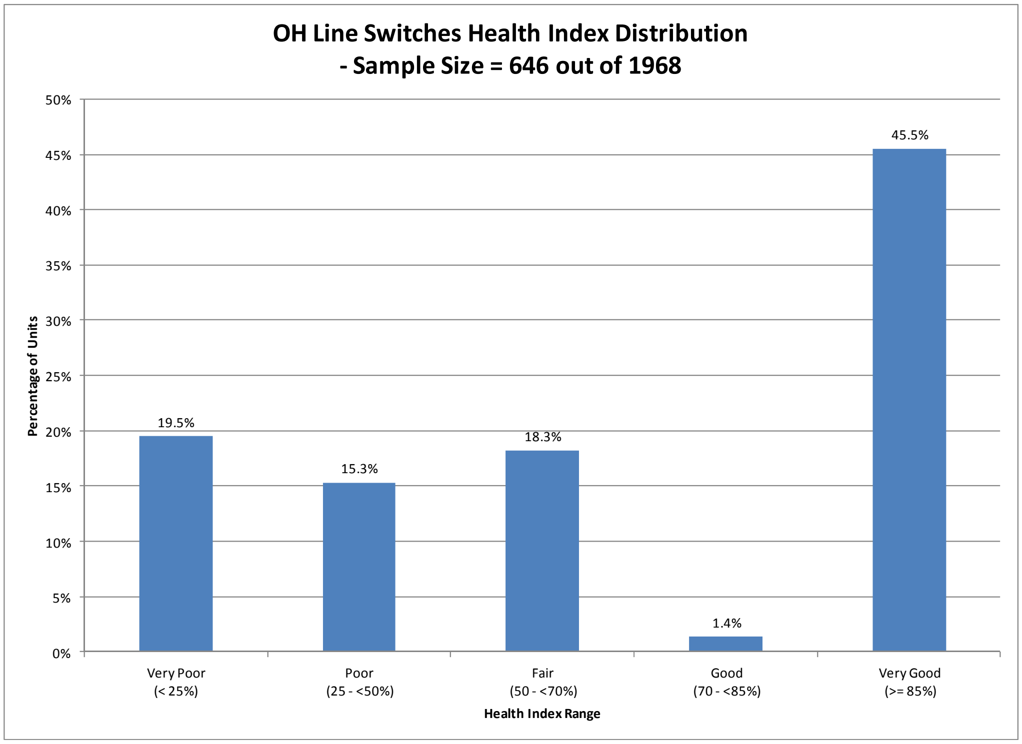

Figure 5-4 Overhead Line Switches Health Index Distribution (Percentage of Units)

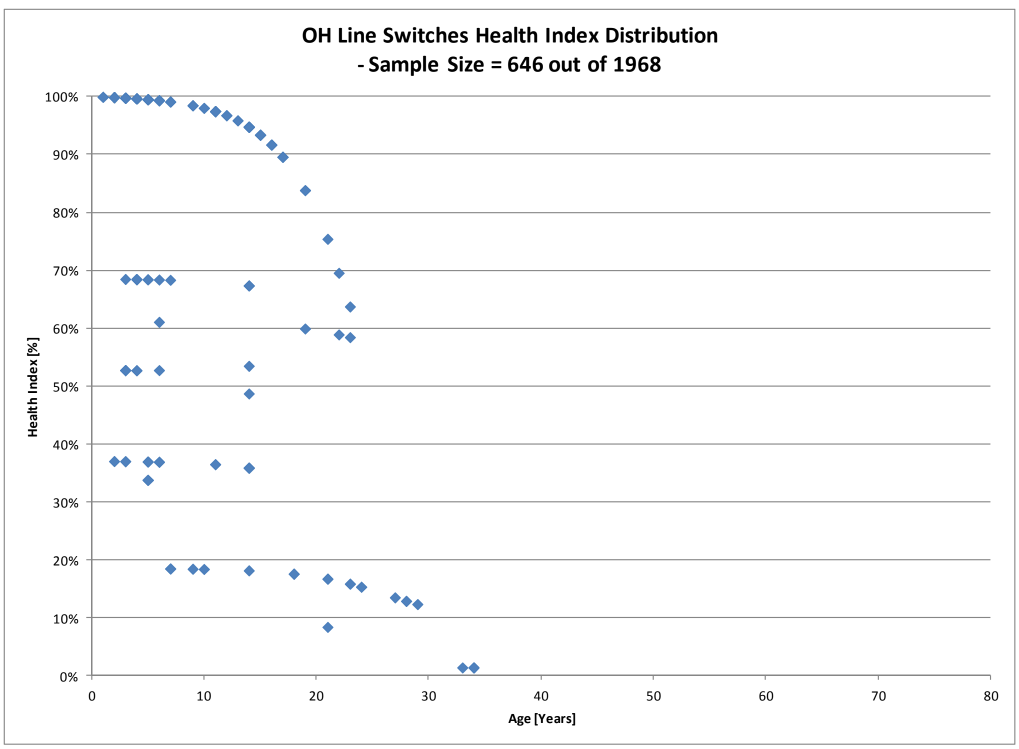

Figure 5-5 Overhead Line Switches Health Index vs Age

5.5 Overhead Line Switches Condition-Based Flagged-For-Action Plan

As it is assumed that Overhead Line Switches are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate f(t), as described in Section II.2.2. This means the Flagged-For-Action Plan is based on the number of expected failures in a given year.

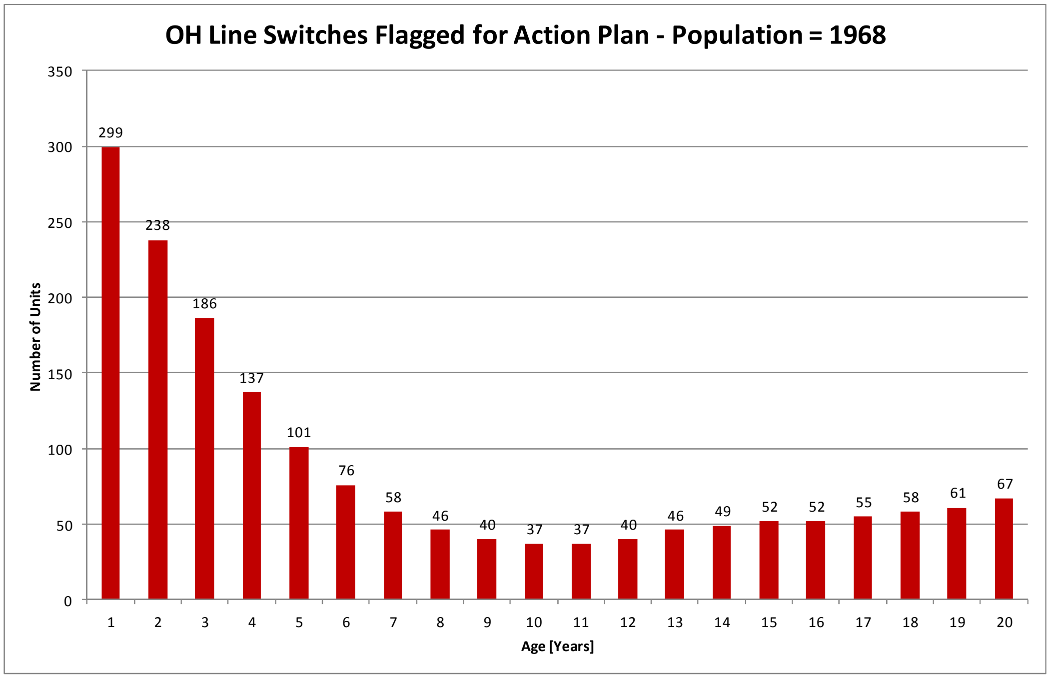

Figure 5-6 Overhead Line Switches Condition-Based Flagged-For-Action Plan

5.6 Overhead Line Switches Data Analysis

The data available for Overhead Line Switches includes age, inspections, and location.

5.6.1 Overhead Line Switches Data Availability Distribution

Inspection information was taken from the asset management. If no entry was found for an asset, it was assumed that there is no sufficient information on the status of the unit, and the assessment has to rely on its physical age. If however no entry was found for a parameter, it was assumed that such a parameter has no issue, thus being in good status.

The average DAI for Overhead Line Switches is 14%, due to the small sample size.

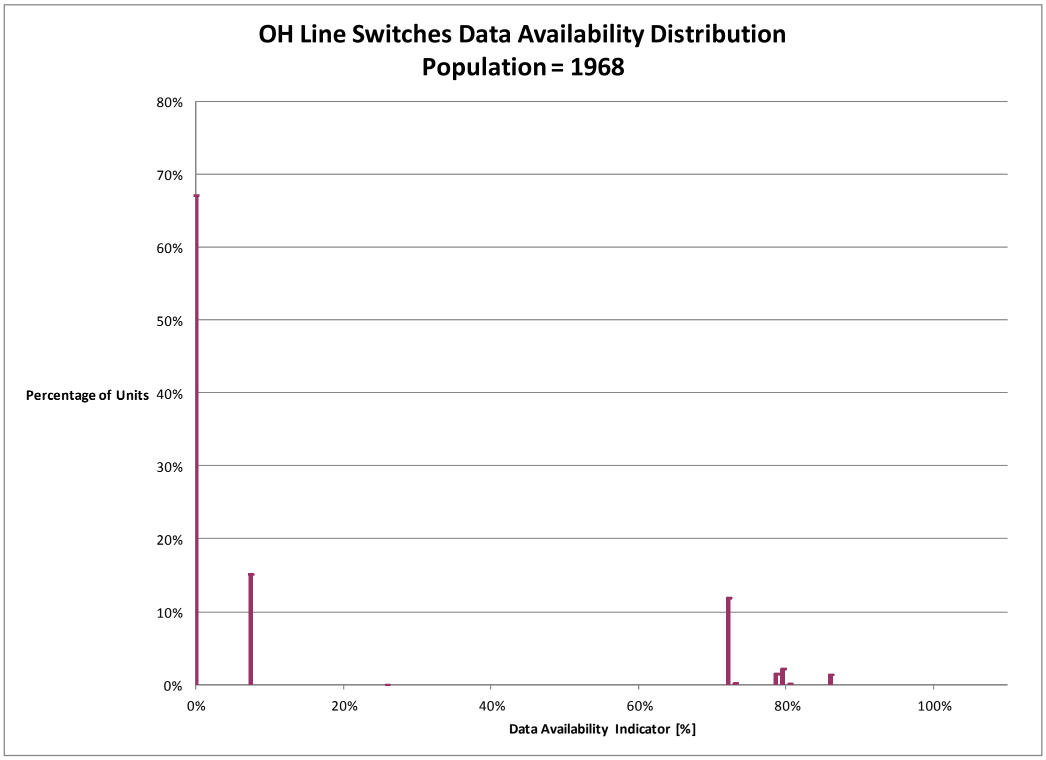

Figure 5-7 Overhead Line Switches Data Availability Distribution

5.6.2 Overhead Line Switches Data Gap

In this asset group, very few units have the required information specified in the Health Index formula. For future ACA study, their inspection maintenance records need to be stored in asset management database even if no defect is found. This is because their condition assessment heavily relies on the historic trend of such records.

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6 Pad-Mounted Transformers

Pad-mounted transformers are used in underground distribution systems to step voltages down from primary system voltages to utilization voltages such as 120/240V and 600/347V.

Pad-mounted transformers are housed in low-profile metal enclosures which generally have an oil-filled compartment for the transformer windings and under-oil switches and protection as well as an air compartment under a hinged door for access to connections, switching and protection. The enclosure is placed on top of a concrete foundation which allows access for incoming cables. Foundations of 6'x6' by 3 feet deep are commonly utilized. Modern pad-mounted transformers are dead-front, with incoming and feed-through connections made using separable insulated connectors.

Fuses and switches are housed in the oil-filled compartment. Single-phase pad-mounted distribution transformers have ratings from 10 to 167kVA. Three-phase pad-mounted transformers are often used in industrial and commercial applications and are generally available in ratings from 45 to 2500kVA.

6.1 Pad-Mounted Transformers Degradation Mechanism

Degradation of pad-mounted transformers can occur due to the following mechanisms:

- Corrosion of the pad-mounted enclosure and tank
- Deterioration of foundations
- Deterioration of separable insulated connectors
- Deterioration of switching or fusing devices
- Degradation of internal insulating material
- Degradation of oil

Pad-mounted transformers located in corrosive environments, such as next to major roads that are salted, are particularly prone to enclosure corrosion. Foundation shifting of pad-mounted transformers has been known to be problematic. Deep frost areas or unstable soil conditions can lead to movement of the foundation. Rubber encapsulated separable insulated connectors will deteriorate with multiple operations and are known to degrade if they are coated with transformer oil. Deterioration of the pad-mounted transformer can also be due to problems such as: switch breakage, leakage of under-oil fuses, and deterioration of dry-well canisters.

The life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Insulation condition can also be affected by voltage and current surges. Therefore, a combination of condition, age and load-based criteria is commonly used to determine the useful remaining life of distribution transformers.

Distribution transformers sometimes need to be replaced because of non-condition related factors such as mechanical damage by vehicles or customer load growth. If a transformer is simply overloaded, a decision is required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labour cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

Visual inspections provide considerable information on transformer asset condition. Leaks, rusting, and deteriorated connectors can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

The consequences of distribution transformer failure can be severe because of the street level location of this equipment. Though rare, pad-mounted transformers can fail with sufficient energy release to rupture the tank and release oil into the surrounding environment. Many utilities treat residential pad-mounted transformers as run-to-failure assets.

6.2 Pad-Mounted Transformers Health Index Formulation

This section presents the Health Index Formula that was developed and used for VC Pad-Mounted Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows:

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

Health Index condition and sub-condition parameters and condition criteria are as follows:

6.2.1 Pad-Mounted Transformers Condition and Sub-Condition Parameters

Table 6-1 Pad-Mounted Transformers Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	CPS Lookup Table
1	Physical Condition	1	Table 6-2
2	Connection & Insulation	2	Table 6-3
3	Service Record	2	Table 6-4
	De-rating multiplier (DR)		Table 6-7

Table 6-2 Pad-Mounted Transformers Physical Condition (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Damage on exterior of tank	Table 6-5	2	4
2	Paint on exterior of tank	Table 6-5	1	4
3	Inspection Access	Table 6-5	1	4
4	Collar Base	Table 6-5	1	4
5	Locking Device	Table 6-5	1	4

Table 6-3 Pad-Mounted Transformers Connection & Insulation (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Oil Leak	Table 6-5	4	4
2	Primary Secondary Connections	Table 6-5	2	4
3	Grounding	Table 6-5	1	4
4	Cooling Fins	Table 6-5	2	4
5	Termination	Table 6-5	1	4
6	Bushing	Table 6-5	2	4

Table 6-4 Pad-Mounted Transformers Service Record (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Overall	Table 6-6	2	4
2	Age	Figure 6-1	1	4

6.2.2 Pad-Mounted Transformers Condition Parameter Criteria

<u>Visual Inspections</u>

Table 6-5 Pad-Mounted Transformers Inspection Count Condition Criteria

Condition Rating*	CPF	Description
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where inspection count is calculated based on detection of specific defects as below:

Year	Score				Weight
	OK	Fixed	Monitored	Fix	
2012	0	1	2	4	1
2011					0.9
2010					0.8
2009					0.7
2008					0.6

Inspection count = $\sum Score_i \times Weight_i$

Where i refers to the year the inspection was conducted

Overall Condition

Table 6-6 Pad-Mounted Transformers Overall Condition Criteria

Condition Rating*	CPF	Description (Overall count)
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where overall count is calculated based on overall condition as below:

Year	Score				Weight
	OK	Fixed	Monitored	Fix	
2012	0	1	2	4	1
2011					0.9
2010					0.8
2009					0.7
2008					0.6

Inspection count = $\sum Score_i \times Weight_i$

Where i refers to the year the inspection was conducted

Age

Assume that the failure rate for Pad-Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 30 and 40 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

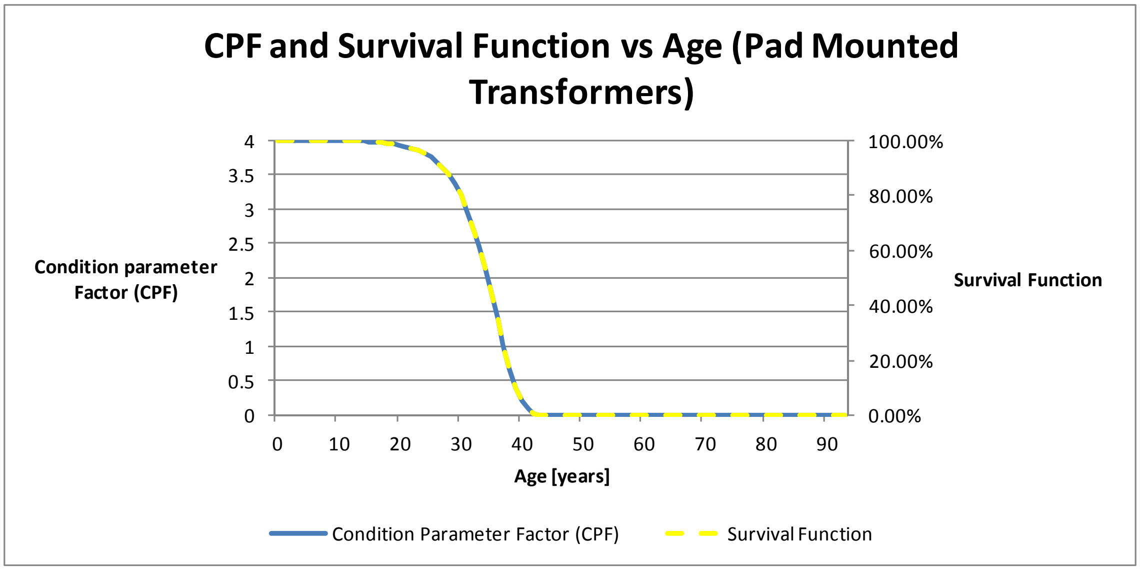

Figure 6-1 Age Condition Criteria (Pad-Mounted Transformers)

De-Rating (DR) Multiplier

Table 6-7 Pad-Mounted Transformers De-Rating Factors

De-Rating Factor	Description
0.3	Poletrans Transformers

6.3 Pad-Mounted Transformers Age Distribution

The age distribution is shown in the figure below. Age was available for the entire population. The average age was found to be 20 years.

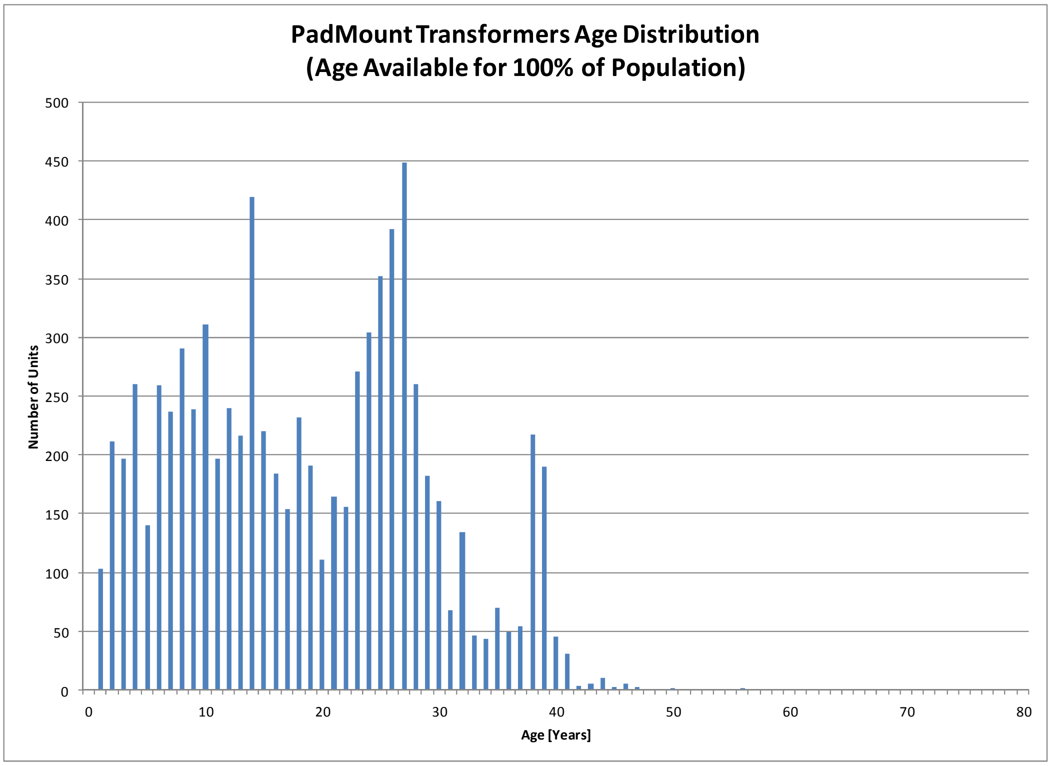

Figure 6-2 Pad-Mounted Transformers Age Distribution

6.4 Pad-Mounted Transformers Health Index Results

There are 8722 in-service Pad-Mounted Transformers at VC. 37% of the population does not have any inspection data so the Health Index study for these units is mainly age-driven.

The average Health Index for this asset group is 94%. Approximately 1.2% of the units were found to be in poor or very poor condition.

The Health Index Results are as follows:

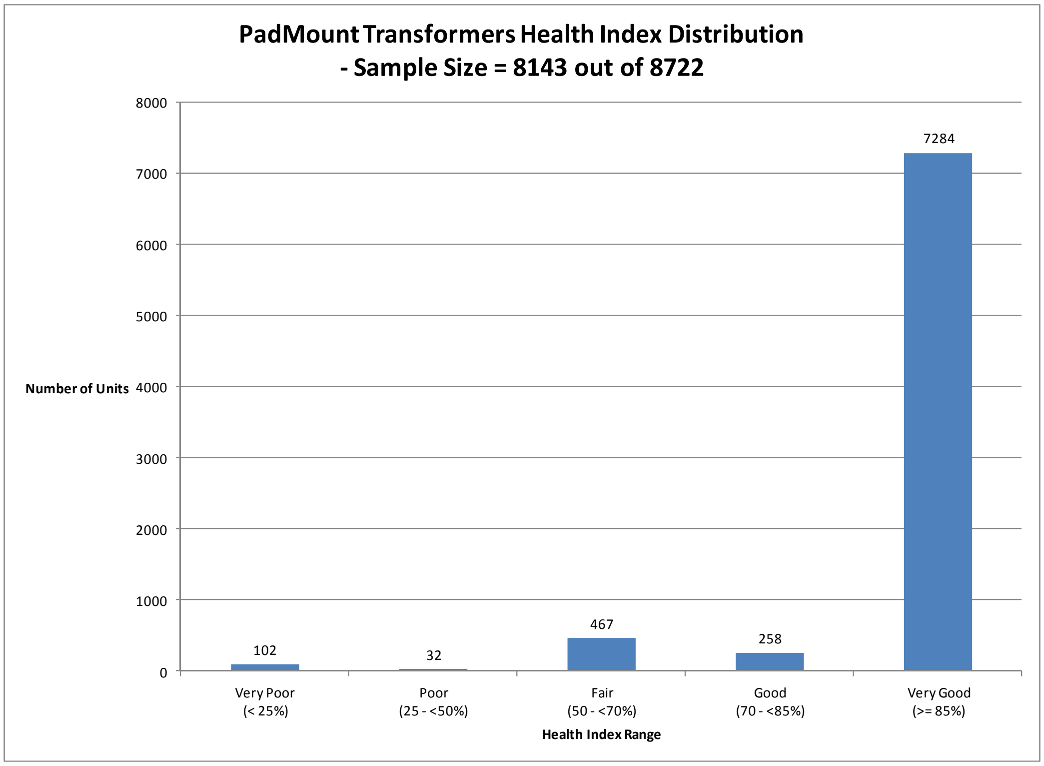

Figure 6-3 Pad-Mounted Transformers Health Index Distribution (Number of Units)

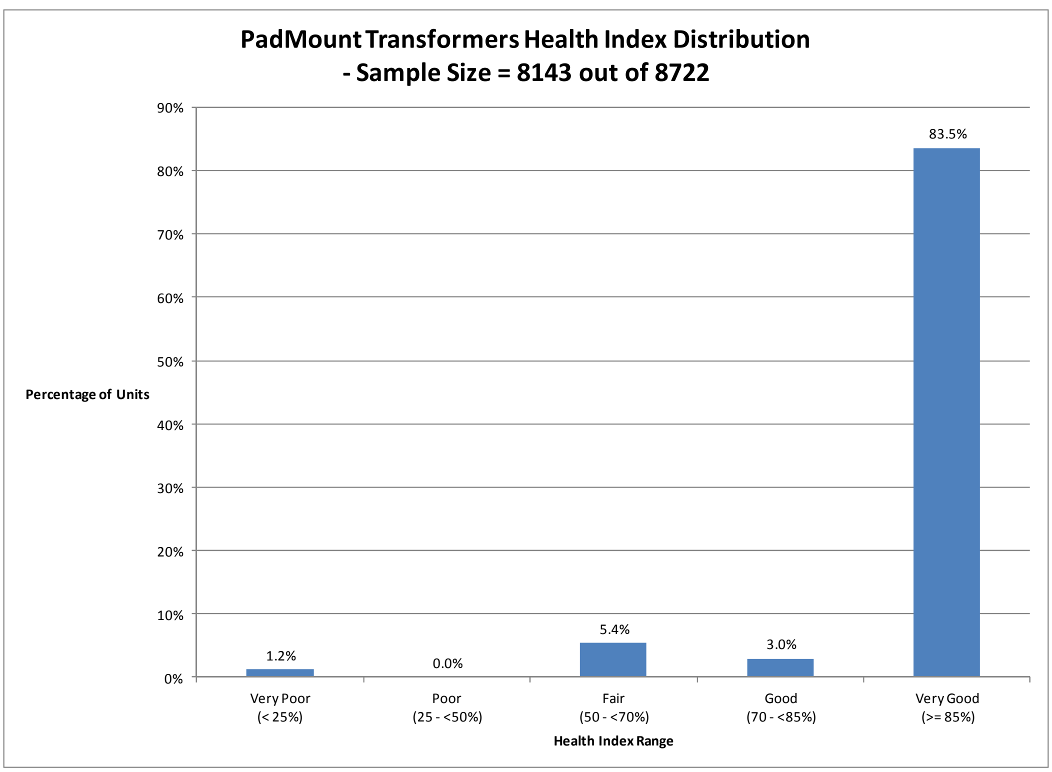

Figure 6-4 Pad-Mounted Transformers Health Index Distribution (Percentage of Units)

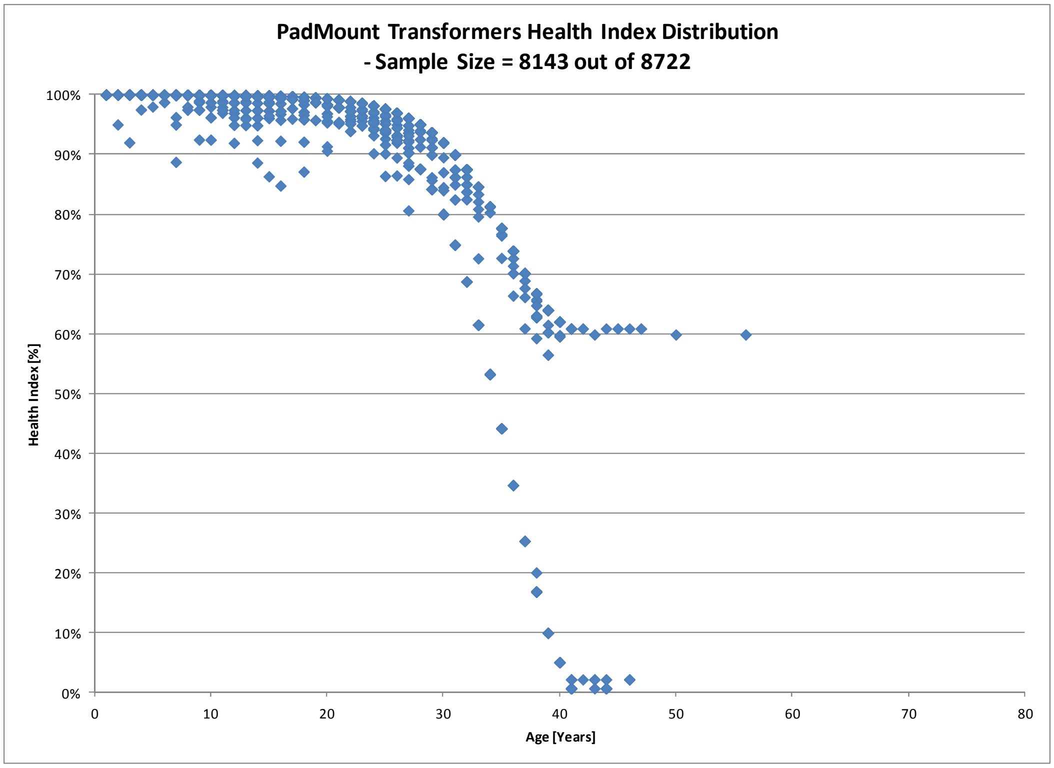

Figure 6-5 Pad-Mounted Transformers Health Index Distribution by Value (Percentage of Units)

6.5 Pad-Mounted Transformers Condition-Based Flagged-For-Action Plan

As it is assumed that Pad-Mounted Transformers are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate, f(t), as described in Section II.2.2. This means the Flagged-For-Action Plan is based on the number of expected failures in a given year.

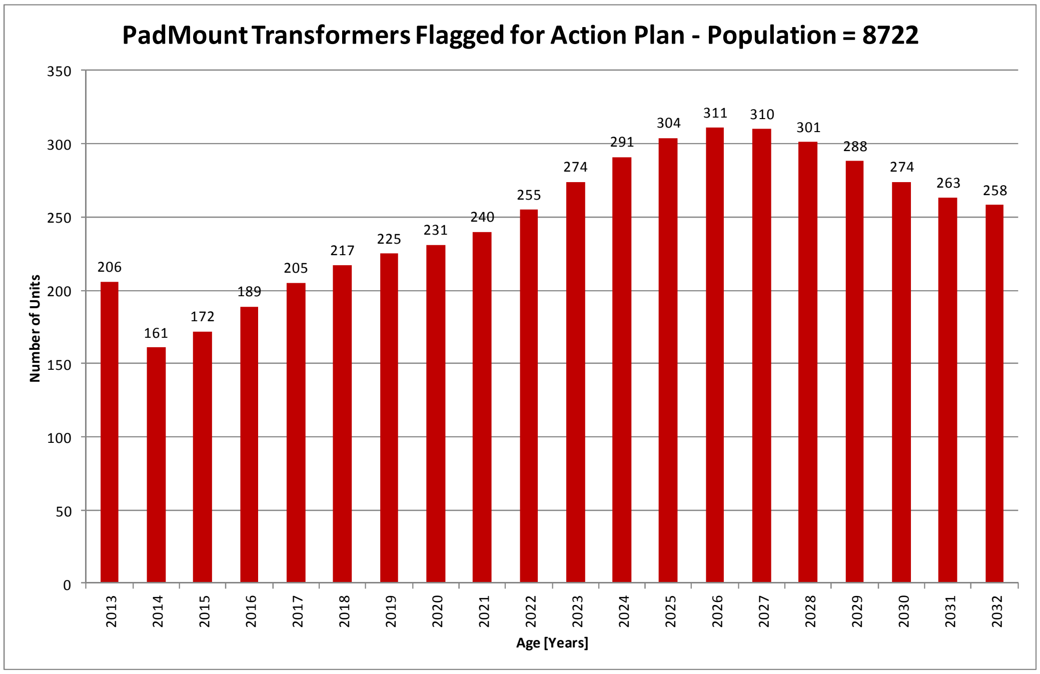

Figure 6-6 Pad-Mounted Transformers Condition-Based Flagged-For-Action Plan

6.6 Pad-Mounted Transformers Data Analysis

The data available for Pad-Mounted Transformers includes age and inspection results.

6.6.1 Pad-Mounted Transformers Data Availability Distribution

Inspection information was taken from the asset management. If no entry was found for an asset, it was assumed that the inspection results were perfect. All parameters that are derived from inspection data are given a perfect score. Parameters for which this applies are:

- Rust
- Oil Leak
- Connection
- Grounding
- Overall Condition

The average DAI for Pad-Mounted Transformers is 67%.

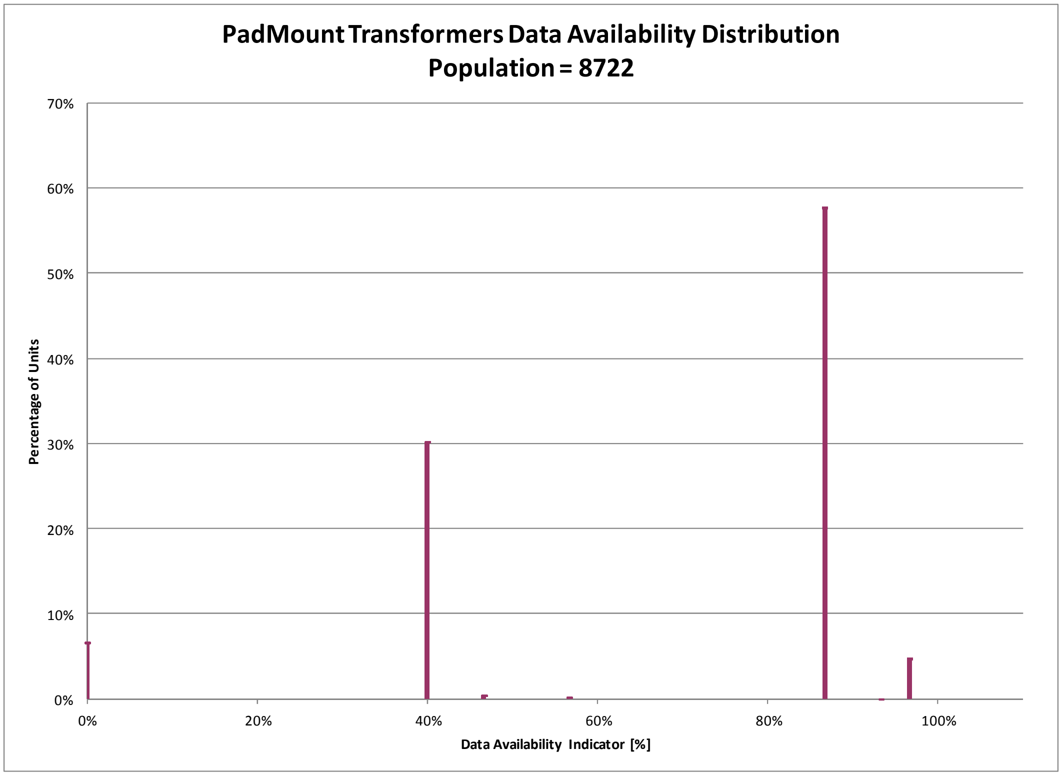

Figure 6-7 Pad-Mounted Transformers Data Availability Distribution

6.6.2 Pad-Mounted Transformers Data Gap

In this asset group, only part of units have the required information specified in the Health Index formula. For future ACA study, their inspection maintenance records need to be stored in asset management database even if no defect is found. This is because their condition assessment heavily relies on the historic trend of such records.

Besides, some additional helpful data that can be collected are:

<table>
<tr><th>Data Gap (Sub-Condition Parameter)</th><th>Parent Condition Parameter</th><th>Priority</th><th>Object or Component Addressed</th><th>Description</th><th>Source of Data</th></tr>
<tr><td>Overall</td><td rowspan="2">Service Record</td><td>☆</td><td>Transformer</td><td>General status evaluation based on routine operation and inspection</td><td>Operation Record</td></tr>
<tr><td>Loading</td><td>☆ ☆</td><td>Transformer load</td><td>Monthly 15 min peak load throughout years</td><td>Operation record</td></tr>
</table>

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7 Vault Transformers

Vault-type distribution transformers are generally installed in a dedicated compartment in a building or under a sidewalk in locations where there is not sufficient room for a pad-mounted transformer. Vault-type transformers are often used in secondary networks and spot networks. They are available for primary voltages from 1.2 to 34.5kV in ratings generally up to 1000kVA.

As vault transformers are often located in harsh environments, vault transformer design often includes enhancements to the protective coatings on the steel walls. Some vault-type transformers may be used in submersible applications.

7.1 Vault Transformers Degradation Mechanism

Degradation of vault-type transformers can occur due to the following mechanisms:

- Corrosion of the tank
- Deterioration of internal switching or fusing devices
- Degradation of internal insulating material
- Degradation of oil

Vault-type transformers are often located in corrosive environments and are prone to enclosure corrosion. Deterioration of the vault-type transformer can also be due to problems such as: switch breakage and leakage of under-oil fuses.

The life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, rusting, and deteriorated connectors can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

The consequences of vault–type transformer failure can be severe because of the in-building or under side-walk location of this equipment. Though rare, vault-type transformers can fail with sufficient energy release to rupture the tank and release oil into the surroundings.

7.2 Vault Transformers Health Index Formulation

This section presents the Health Index Formula that was developed and used for VC Vault Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

7.2.1 Vault Transformers Condition and Sub-Condition Parameters

Given the fact that no Vault Transformers have information other than age, in this study only age data are used for Health Index study.

Table 7-1 Vault Transformers Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Service Record	1	Table 7-2

Table 7-2 Vault Transformers Service Record (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Age	Figure 7-1	1	4

7.2.2 Vault Transformers Condition Criteria

<u>Age</u>

Assume that the failure rate for Vault Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 30 and 40 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

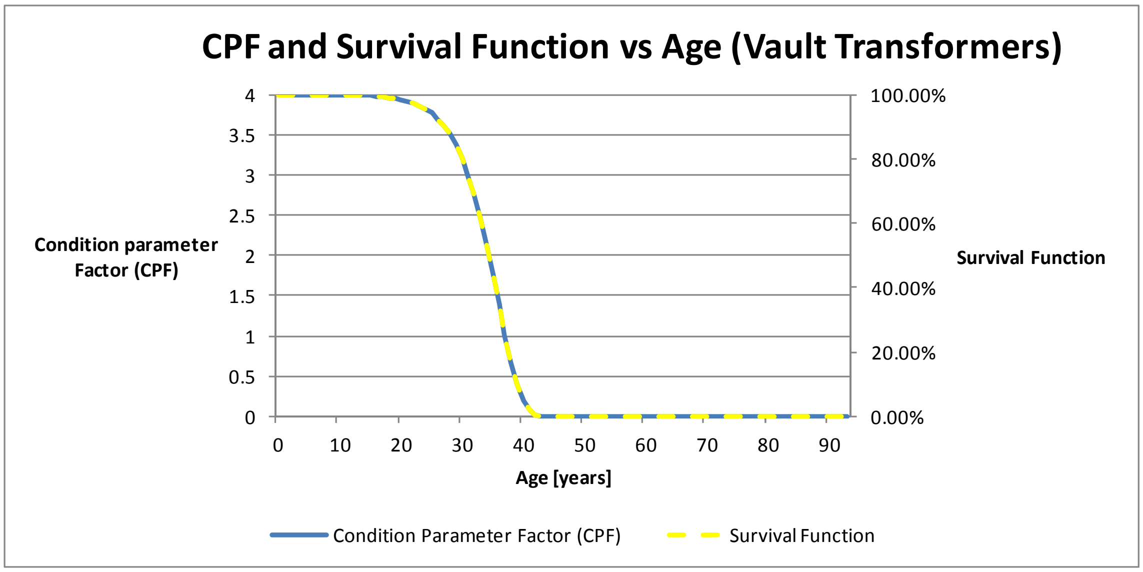

Figure 7-1 Age Condition Criteria (Vault Transformers)

7.3 Vault Transformers Age Distribution

The age distribution is shown in the figure below. Age was available for 70% of the population. The average age was found to be 7 years.

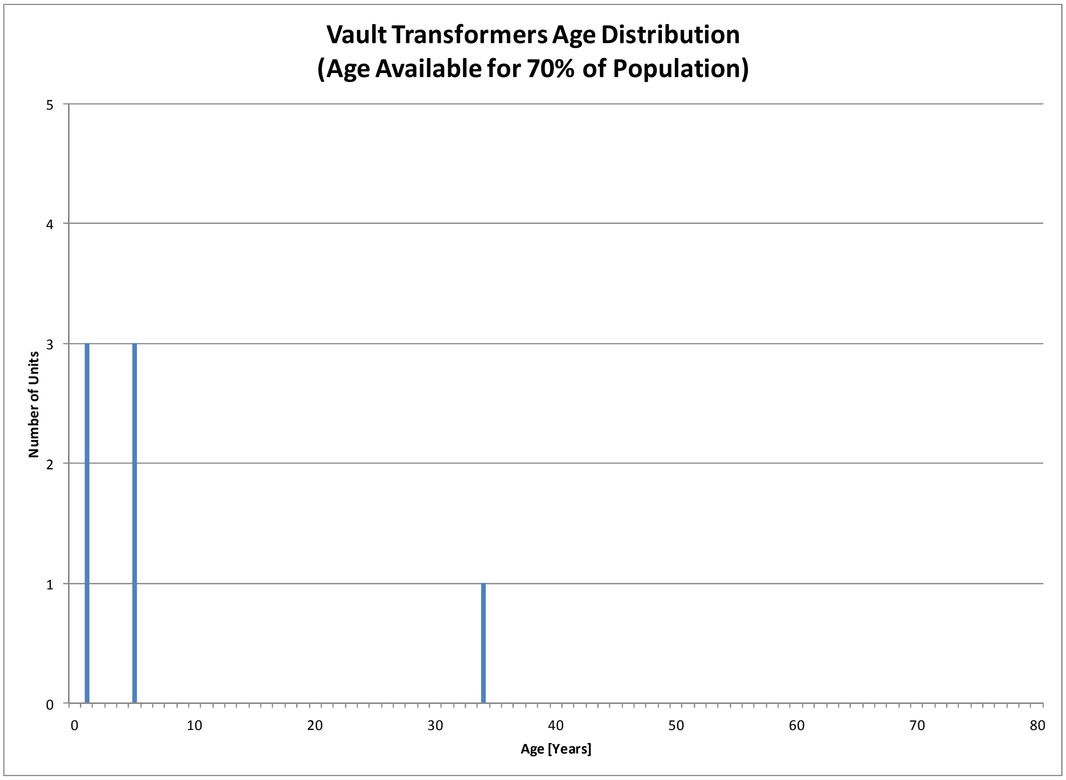

Figure 7-2 Vault Transformers Age Distribution

7.4 Vault Transformers Health Index Results

There are 10 in-service Vault Transformers at VC. It is assumed that the absence of an entry in the inspection database implies that the status of a unit is unknown. On that basis, 70% units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 82%.

The Health Index Results are as follows:

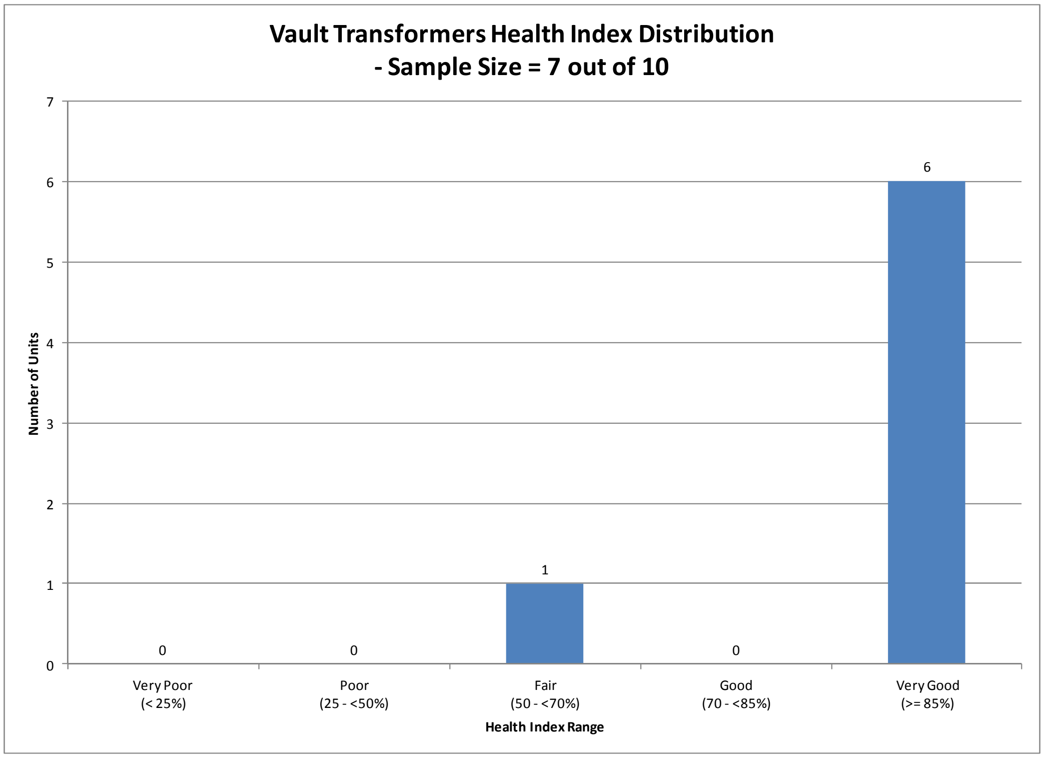

Figure 7-3 Vault Transformers Health Index Distribution (Number of Units)

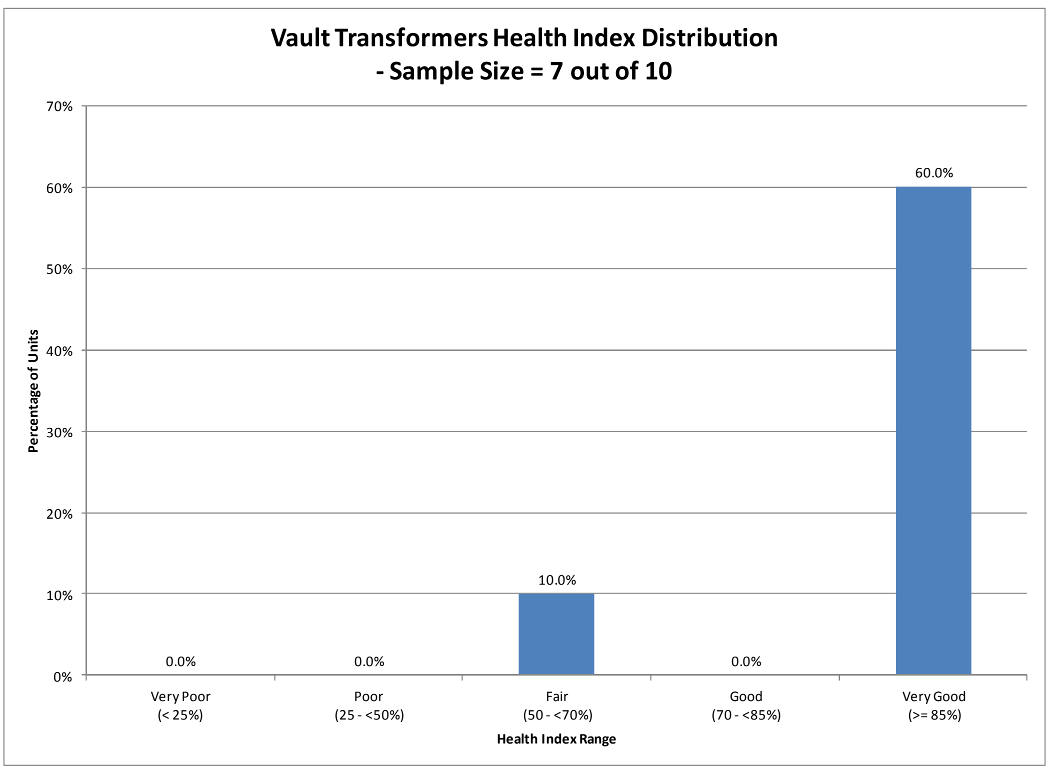

Figure 7-4 Vault Transformers Health Index Distribution (Percentage of Units)

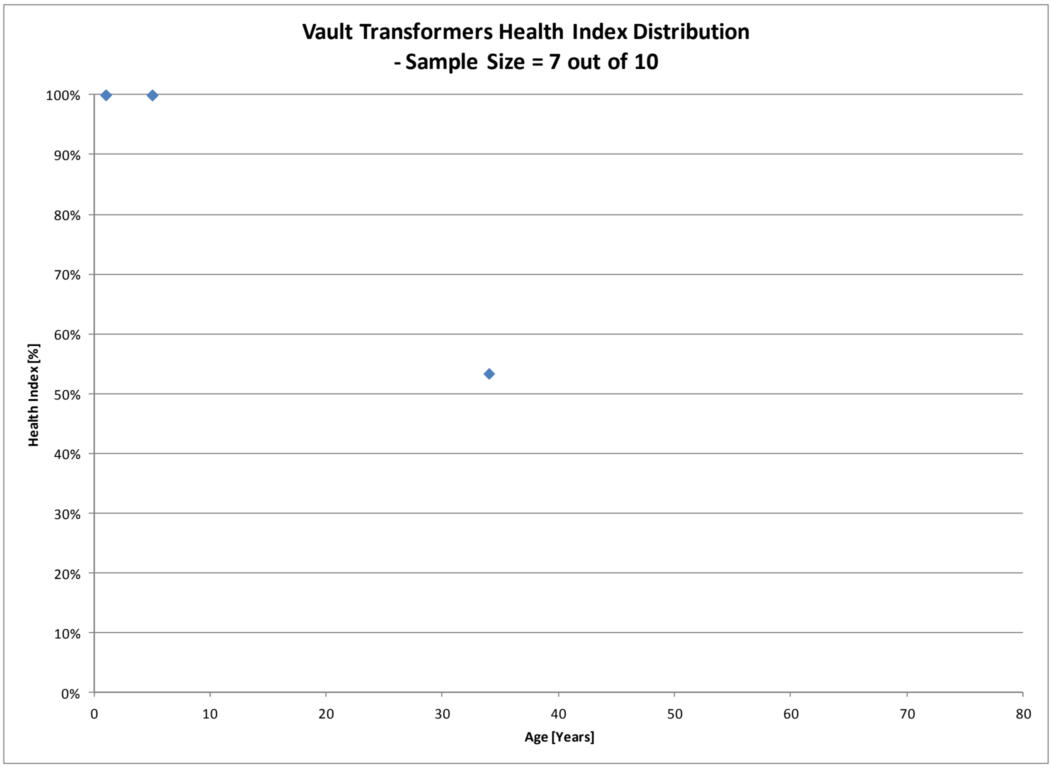

Figure 7-5 Vault Transformers Health Index vs Age

7.5 Vault Transformers Condition-Based Flagged-For-Action Plan

As it is assumed that Vault Transformers are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate f(t), as described in Section II.2.2. This means the Flagged-For-Action Plan is based on the number of expected failures in a given year.

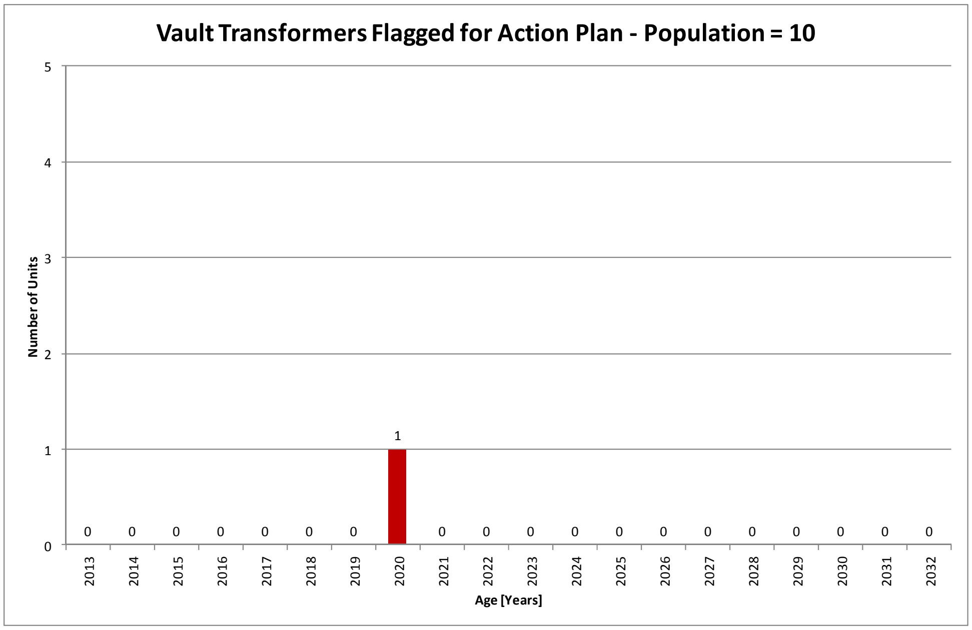

Figure 7-6 Vault Transformers Condition-Based Flagged-For-Action Plan

7.6 Vault Transformers Data Analysis

The data available for Vault Transformers includes age only.

7.6.1 Vault Transformers Data Availability Distribution

Inspection information was taken from the asset management. If no entry was found for an asset, it was assumed that there is no sufficient information on the status of the unit, and the assessment has to rely on its physical age. If however no entry was found for a parameter, it was assumed that such a parameter has no issue, thus being in good status.

The average DAI for Vault Transformers is 28%.

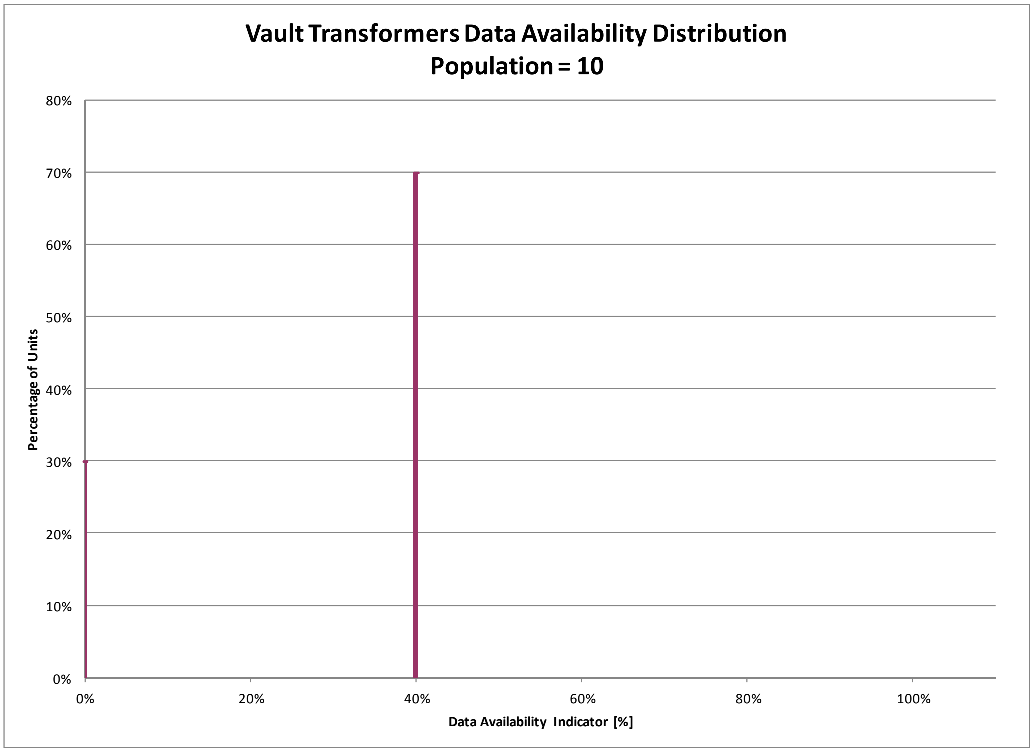

Figure 7-7 Vault Transformers Data Availability Distribution

7.6.2 Vault Transformers Data Gap

In this asset group, no units have inspection data. For future ACA study, their inspection maintenance records need to be stored in asset management even if no defect is found. This is because their condition assessment heavily relies on the historic trend of such records.

The helpful data that can be collected are:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Oil leak	Connection & Insulation	☆☆	Transformer	Findings at routine inspection	Foot patrol inspection
Bushing		☆☆	Transformer	Findings at routine inspection	Foot patrol inspection
Connection Hot Spot		☆	Transformer connection	Findings at routine inspection	IR scan
Tank exterior issue	Physical Condition	☆	Transformer tank	Findings at routine inspection	Foot patrol inspection
Vault Drainage		☆	Transformer vault	Findings at routine inspection	Foot patrol inspection
Overall*	Service Record	☆	Transformer	General status evaluation based on routine operation and inspection	Operation Record
Loading		☆☆	Transformer load	Monthly 15 min peak load throughout years	Operation Record

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8 Submersible Transformers

Like vault transformers, submersible distribution transformers are used in underground or below-grade level vaults, generally installed in a dedicated compartment in a building or under a sidewalk in locations where there is not sufficient room for a pad-mounted transformer. Submersible transformers, however, are rated for occasional submerged operation, and are thus suitable for vaults that are subject to occasional flooding.

8.1 Submersible Transformers Degradation Mechanism

Degradation of vault-type transformers can occur due to the following mechanisms:

- Corrosion of the tank
- Deterioration of internal switching or fusing devices
- Degradation of internal insulating material
- Degradation of oil

Submersible transformers are often located in corrosive environments and are prone to enclosure corrosion. Deterioration of a submersible transformer can also be due to problems such as: switch breakage and leakage of under-oil fuses.

The life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, rusting, and deteriorated connectors can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

The consequences of a submersible transformer failure are mostly reliability impacts and are relatively minor.

8.2 Submersible Transformers Health Index Formulation

This section presents the Health Index Formula that was developed and used for VC Submersible Transformers. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

8.2.1 Submersible Transformers Condition and Sub-Condition Parameters

Given the fact that no Submersible Transformers have information other than age, in this study only age data are used for Health Index study.

Table 8-1 Submersible Transformers Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Service Record	1	Table 8-2

Table 8-2 Submersible Transformers Service Record (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup Table	$WCPF_n$	$CPF_{n.max}$
1	Age	Figure 8-1	1	4

8.2.2Submersible Transformers Condition Criteria

Age

Assume that the failure rate for Submersible Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 30 and 40 years the probability of failure (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age is also shown in the figure below:

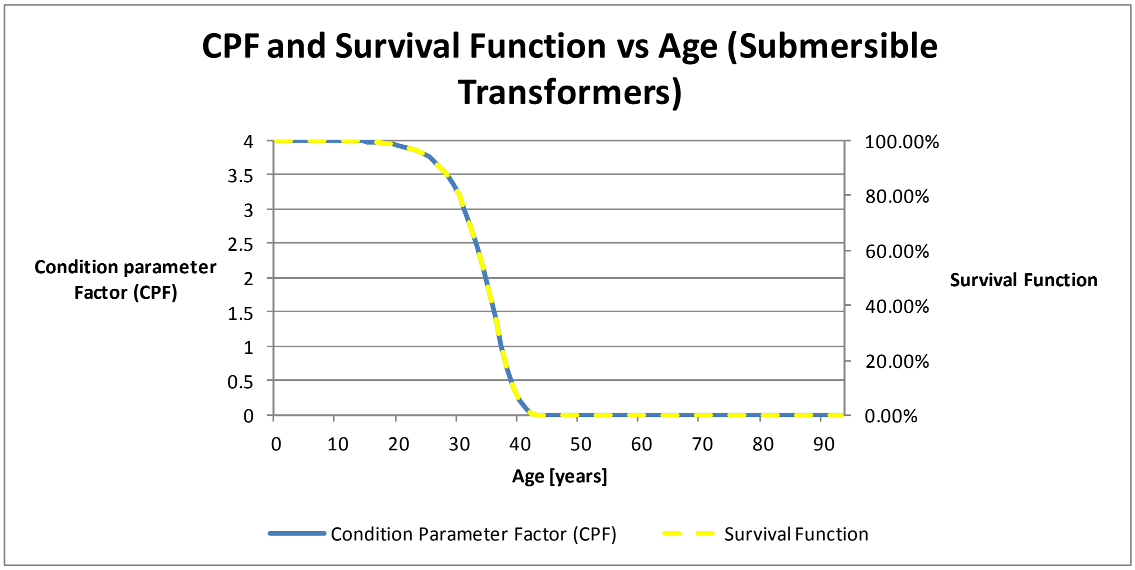

Figure 8-1 Age Condition Criteria (Submersible Transformers)

8.3 Submersible Transformers Age Distribution

The age distribution is shown in the figure below. Age was available for 70% of the population. The average age was found to be 7 years.

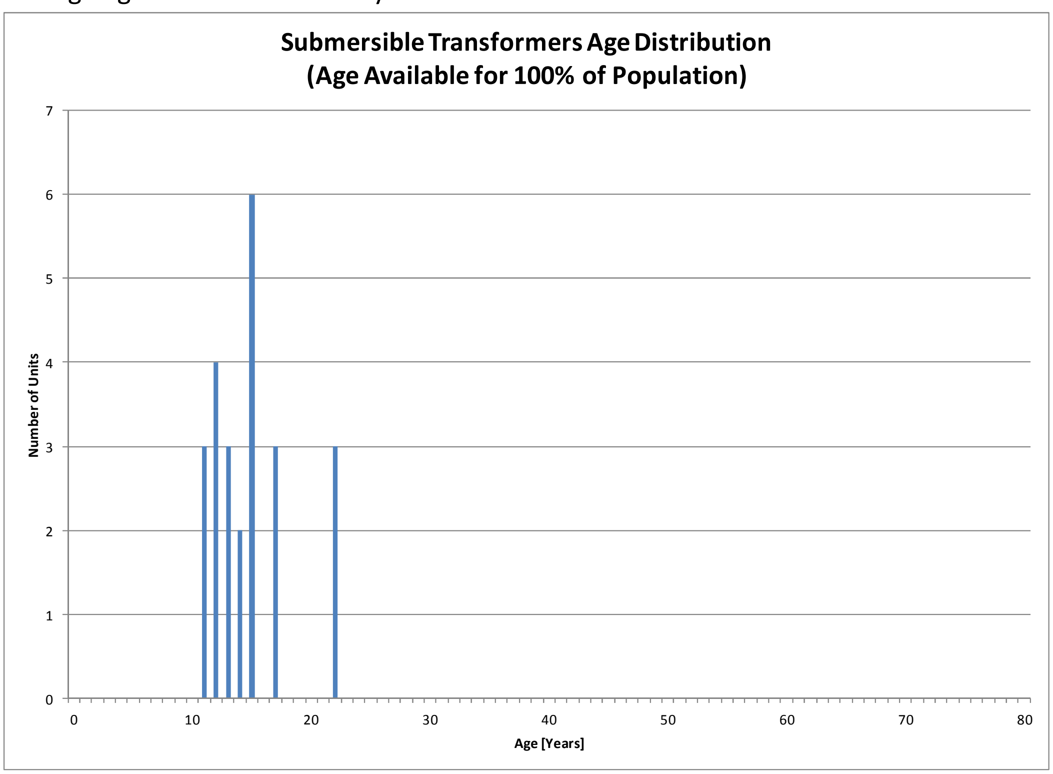

Figure 8-2 Submersible Transformers Age Distribution

8.4 Submersible Transformers Health Index Results

There are 24 in-service Submersible Transformers at VC. It is assumed that the absence of an entry in the inspection database implies that the status of a unit is unknown. On that basis, 100% units were assumed to have had sufficient data for assessment.

The average Health Index for this asset group is 99%. None of the units were found to be in poor or very poor condition due mainly to the de-rating factor applied.

The Health Index Results are as follows:

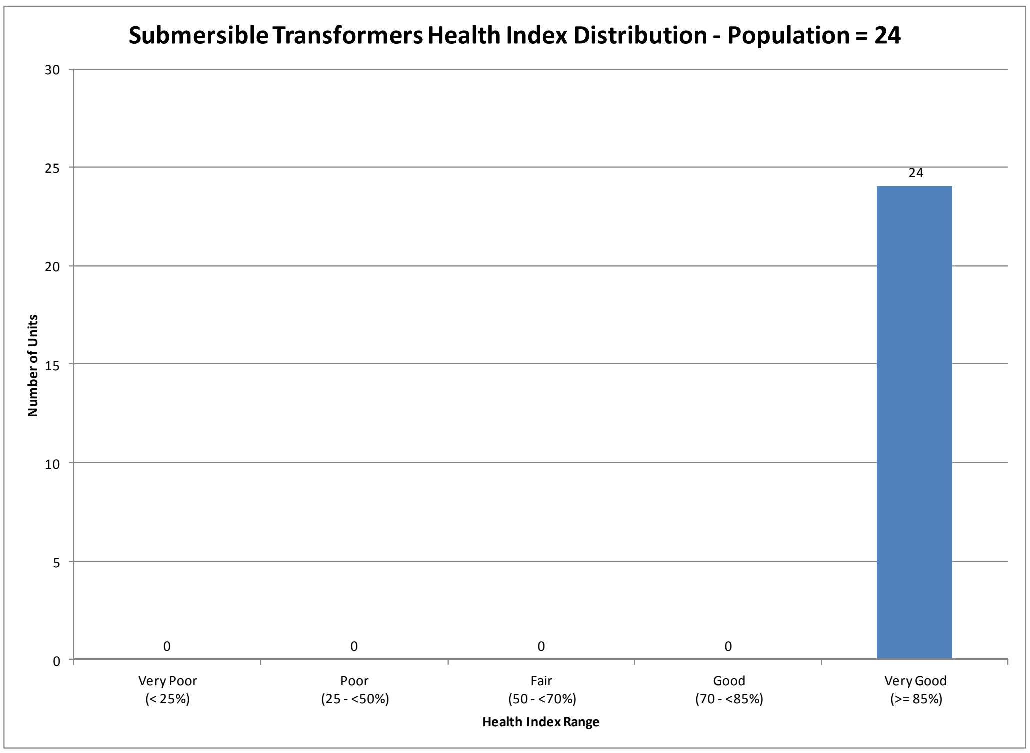

Figure 8-3 Submersible Transformers Health Index Distribution (Number of Units)

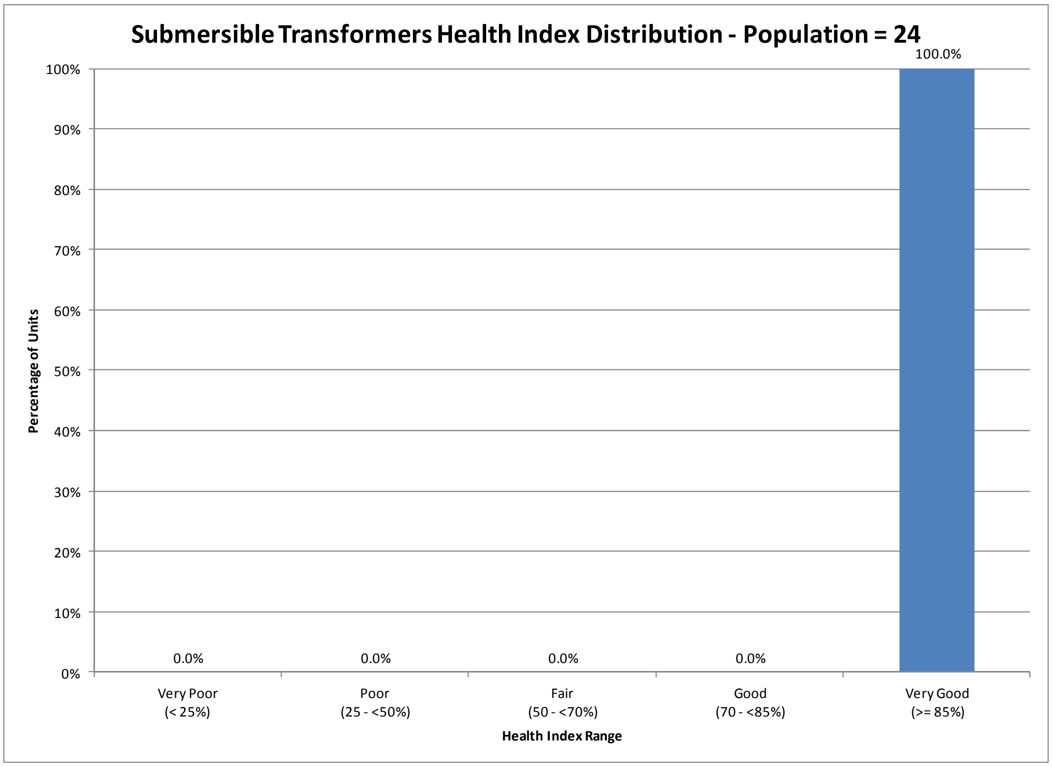

Figure 8-4 Submersible Transformers Health Index Distribution (Percentage of Units)

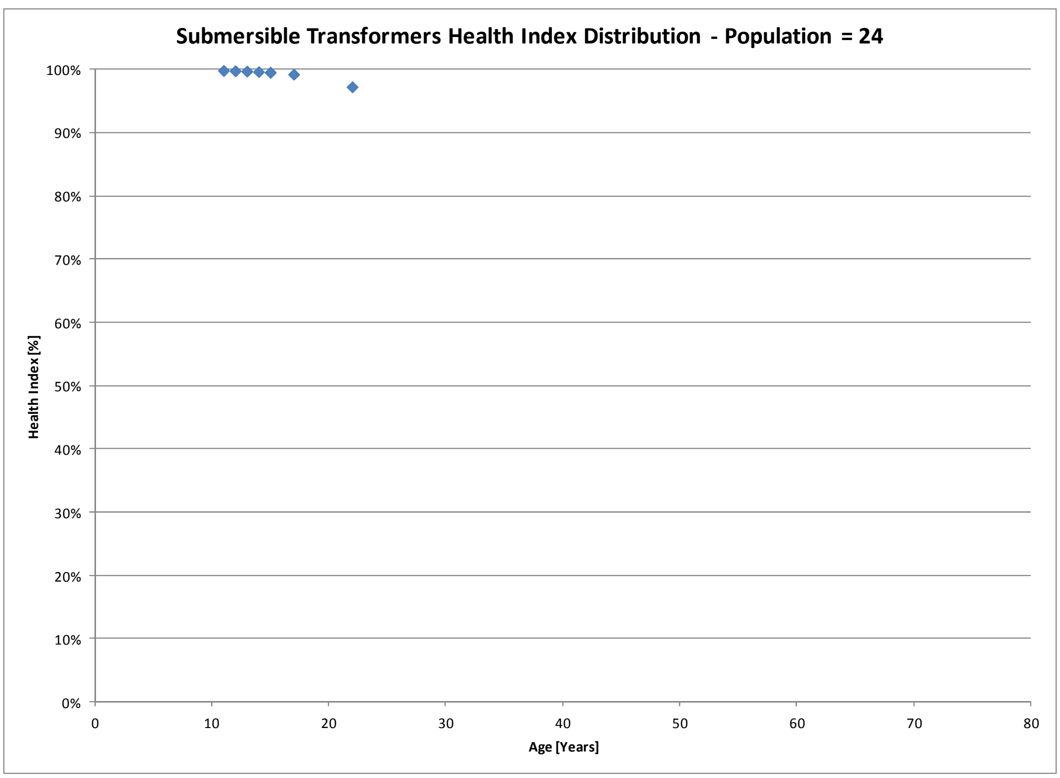

Figure 8-5 Submersible Transformers Health Index vs Age

8.5 Submersible Transformers Condition-Based Flagged-For-Action Plan

As it is assumed that Submersible Transformers are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate f(t), as described in Section II.2.2. This means the Flagged-For-Action Plan is based on the number of expected failures in a given year.

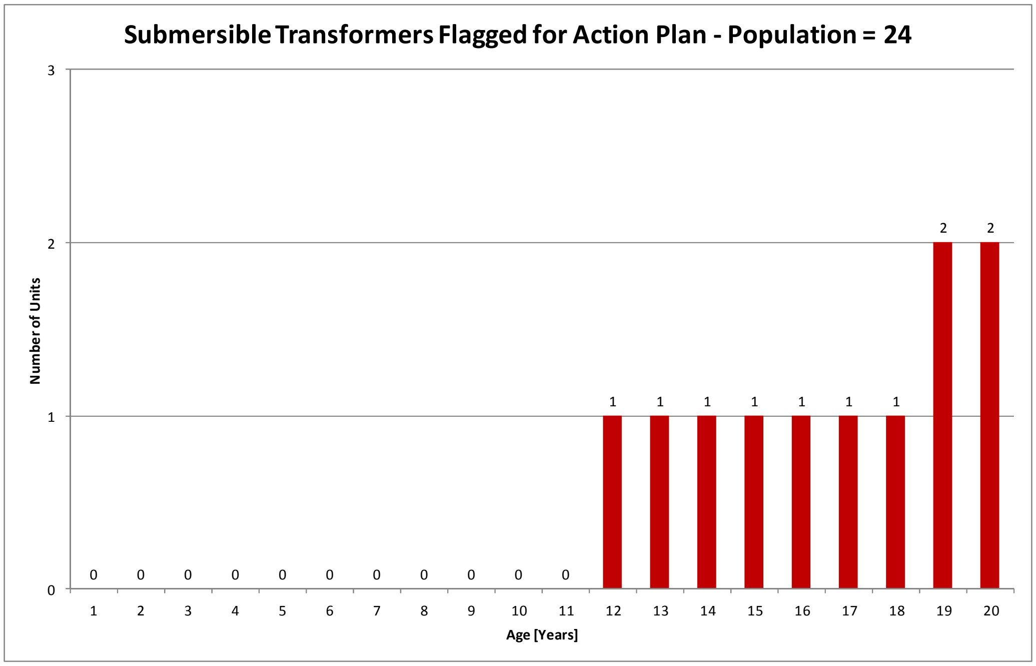

Figure 8-6 Submersible Transformers Condition-Based Flagged-For-Action Plan

8.6 Submersible Transformers Data Analysis

The data available for Submersible Transformers includes age only.

8.6.1 Submersible Transformers Data Availability Distribution

Inspection information was taken from the asset management. If no entry was found for an asset, it was assumed that there is no sufficient information on the status of the unit, and the assessment has to rely on its physical age. If however no entry was found for a parameter, it was assumed that such a parameter has no issue, thus being in good status.

The average DAI for Submersible Transformers is 40%.

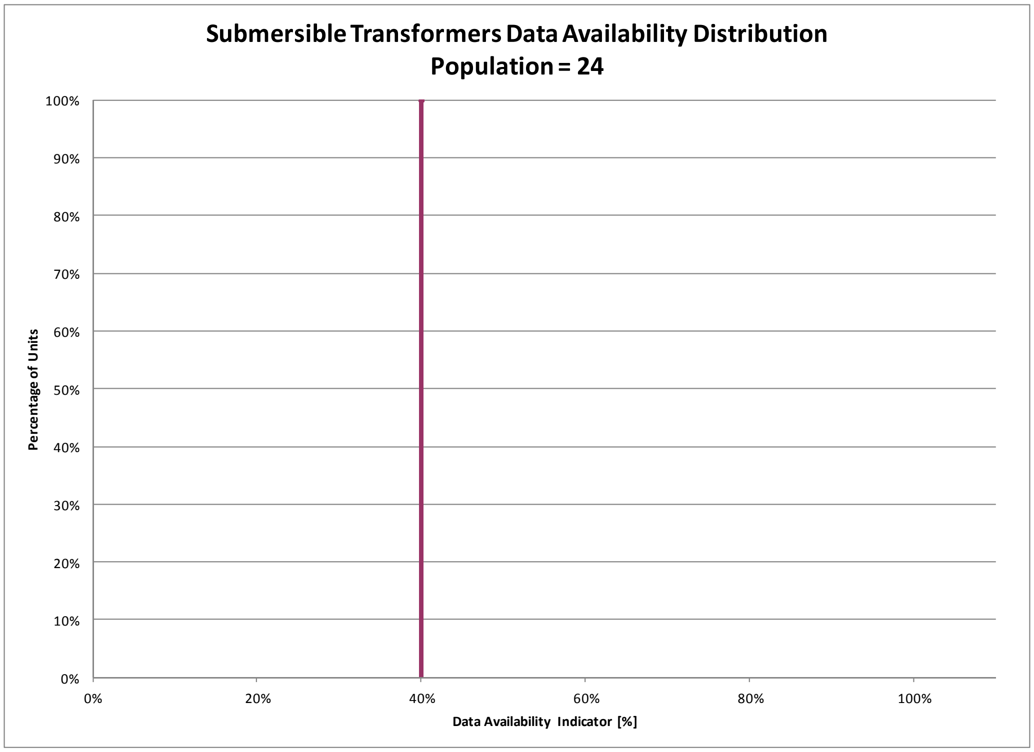

Figure 8-7 Submersible Transformers Data Availability Distribution

8.6.2 Submersible Transformers Data Gap

In this asset group, no units have inspection data. For future ACA study, their inspection maintenance records need to be stored in asset management even if no defect is found. This is because their condition assessment heavily relies on the historic trend of such records.

The helpful data that can be collected are:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Oil leak	Connection & Insulation	✫ ✫	Transformer	Findings at routine inspection	Foot patrol inspection
Bushing		✫ ✫	Transformer	Findings at routine inspection	Foot patrol inspection
Connection Hot Spot		✫	Transformer connection	Findings at routine inspection	IR scan
Tank exterior issue	Physical Condition	✫	Transformer tank	Findings at routine inspection	Foot patrol inspection
Inspection Access		✫	Access	Findings at routine inspection	Foot patrol inspection
Overall	Service Record	✫	Transformer	General status evaluation based on routine operation and inspection	Operation Record
Loading		✫ ✫	Transformer load	Monthly 15 min peak load throughout years	Operation record

9 Pad Mounted Switchgear

This asset class consists of pad-mounted above grade switchgear typically used in underground distribution systems. The switchgear consists of a low profile pad-mounted enclosure with various internal compartments housing cable terminations, switching, and protection equipment.

The pad-mounted gear can be sub-classified as live-front (with exposed electrical components when the doors are opened) or dead-front (with no live parts exposed). The majority of live-front pad mounted switchgear currently in use includes air-insulated gang-operated load-break switches. Dead-front gear utilizes separable insulated connectors and sometimes oil vacuum or SF6 switches.

9.1 Pad Mounted Switchgear Degradation Mechanism

Pad-mounted switchgear degradation can be caused by:

- Mechanical wear and misalignment
- Moisture ingress
- Contamination of internal components
- Corrosion e.g. rusting of the enclosures or operating mechanism
- Degradation of insulated barriers and breakage of insulators
- Failure of internal components such as insulators and fuses

Mechanical wear is impacted by factors such as frequency of switching operations, and the magnitude of continuous and switched load. Moisture and contamination problems are influenced by the dampness of the installation site and the presence of a corrosive environment.

Failures of switchgear can be associated instead with outside influences. For example, pad-mounted switchgear can be damaged by rodents and vehicle accidents. There are other defects that are important and require intervention, but do not result into a failure and can be rectified by field action. For example, graffiti on pad-mounted switchgear is often considered an eyesore and may even conceal important safety and operating signage. Re-painting the outside of the case and replacing the signage can usually be done with no disruption of power. In areas with recurring problems, anti-graffiti paint may be an effective solution.

Some of the degradation modes can be mitigated, failures avoided, and life can be extended with good design and maintenance practices. Rusting of a pad-mounted switchgear enclosure can lead to perforation and a public safety hazard. Touch-up and re-painting may delay the rusting process, but eventually a planned replacement of the equipment will be required. Accumulation of dirt and pollution can often be removed by cleaning. On-line cleaning using CO2 or dry ice is one of the technologies used successfully. Inspection and thermo-graphic analysis can detect loose or degrading connections. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

The first generation of pad mounted switchgear was first introduced in early 1970’s and many of these units are still in good operating condition. In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure.

Consequences of pad-mounted switchgear failure include customer interruptions, health and safety as well as environmental consequences. For instance failures caused by fuse malfunctions can result in a catastrophic pad-mounted switchgear failure.

9.2 Pad Mounted Switchgear Health Index Formula

This section presents the Health Index Formula that was developed and used for VC’s Pad Mounted Switchgear. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

9.2.1Pad Mounted Switchgear Condition and Sub-Condition Parameters

Table 9-1 Condition Parameter and Weights

m	Condition Parameter	WCP_m	Sub-Condition Parameters
1	Physical Condition	6	Table 9-2
2	Switch/Fuse Condition	3	Table 9-3
3	Insulation	3	Table 9-4
4	Service Record	8	Table 9-5

Table 9-2 Physical Condition Sub-Condition Parameters and Weights (m=1)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Exterior of Cubicle - Paint	1	Table 9-6
2	Exterior of Cubicle - damage	1	Table 9-6
3	Access/Doors	1	Table 9-6
4	Base Condition	1	Table 9-6

Table 9-3 Switch/Fuse Sub-Condition Parameters and Weights (m=2)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Primary Connections	2	Table 9-6
2	Primary Terminations	1	Table 9-6
3	Grounding	1	Table 9-6

Table 9-4 Insulation Sub-Condition Parameters and Weights (m=3)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Barrier Boards	1	Table 9-6

Table 9-5 Service Record Sub-Condition Parameters and Weights (m=4)

n	Sub-Condition Parameter	$WCPF_n$	Condition Criteria Table
1	Overall	2	Table 9-7
2	Age	1	Figure 9-1

9.2.2 Pad Mounted Switchgear Condition Criteria

Visual Inspections

Table 9-6 Visual Inspection Condition Criteria

Condition Rating	CPF	Description
A	4	0
B	3	1
C	2	2
D	1	3
E	0	4

Where inspection count is calculated based on Veridian Inspection Database as below:

Year	Score OK	Score Monitored	Score Fix	Weight
2012	0	2	4	1
2011				0.9
2010				0.8
2009				0.7
2008				0.6

Inspection count = $\sum Score_i \times Weight_i$

Where i refers to the year the inspection was conducted

Overall Condition

Table 9-7 Overall Condition Criteria

Condition Rating*	CPF	Description
A	4	0
B	3	3
C	2	6
D	1	9
E	0	12

Where overall count is calculated based on detection of ANY defect as below:

Year	Score: OK	Score: Monitored	Score: Fix	Weight
2012	0	2	4	1
2011				0.9
2010				0.8
2009				0.7
2008				0.6

Inspection count = $\sum Score_i \times Weight_i$

Where i refers to the year the inspection was conducted

Age

Assume that the failure rate Pad Mounted Switchgear exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 20 and 40 years the probability of failures (P_f) for this asset are 15% and 85% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

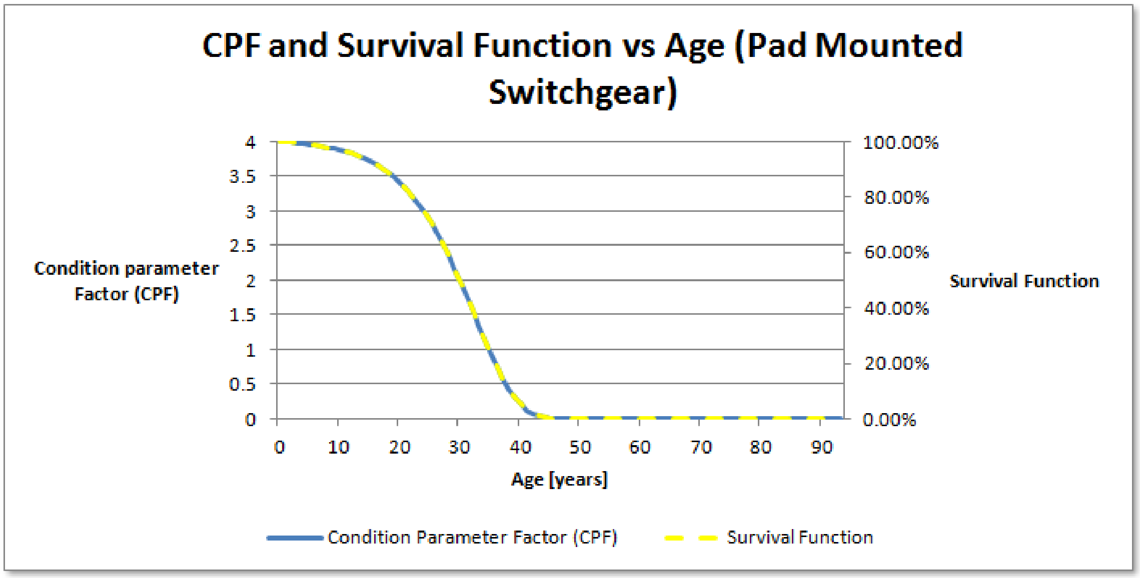

Figure 9-1 Age Criteria (Pad Mounted Switchgear)

9.3 Pad Mounted Switchgear Age Distribution

The age distribution is shown in the figure below. Age was available for 98% of the entire population. The average age was found to be 16 years.

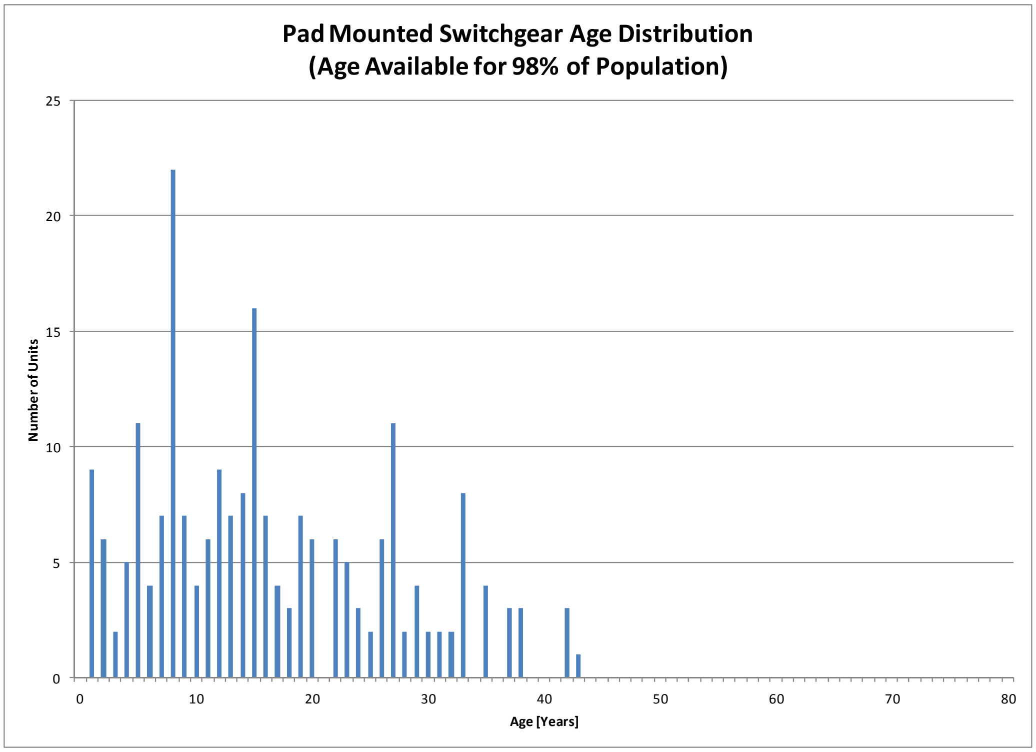

Figure 9-2 Pad Mounted Switchgear Age Distribution

9.4 Pad Mounted Switchgear Health Index Results

There are 221 in-service Pad Mounted Switchgear at VC. Most of them have only age data available for assessment.

The average Health Index for this asset group is 83%. Approximately 8.1% of the units were found to be in very poor condition.

The Health Index Distribution is shown in the following tables.

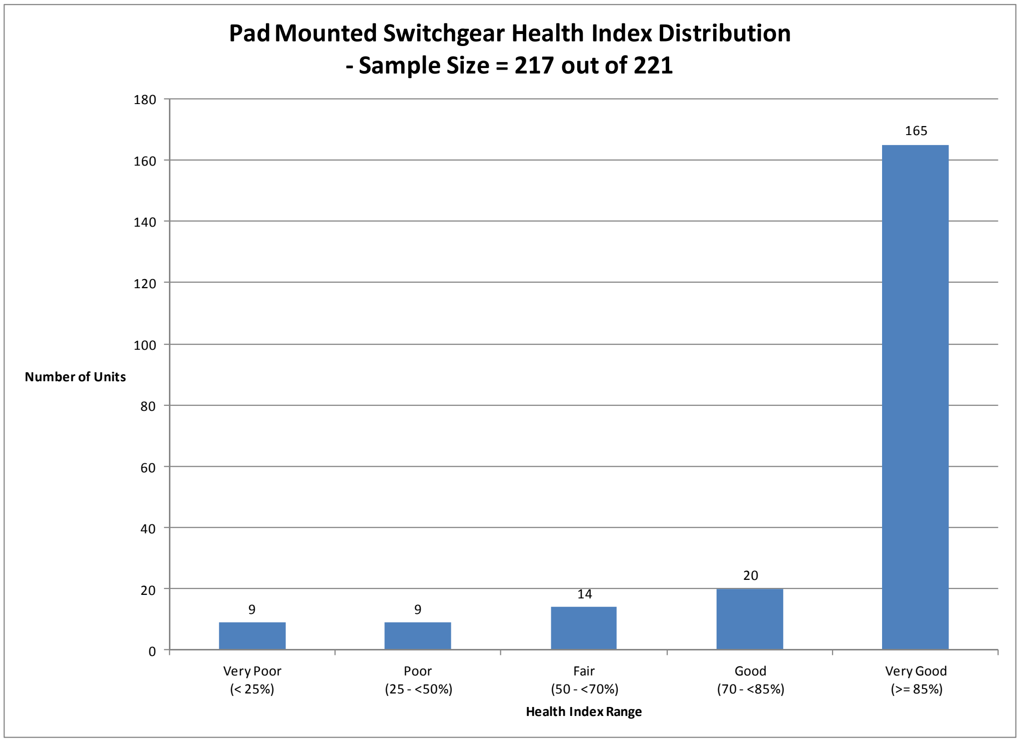

Figure 9-3 Pad Mounted Switchgear Health Index Distribution (Number of Units)

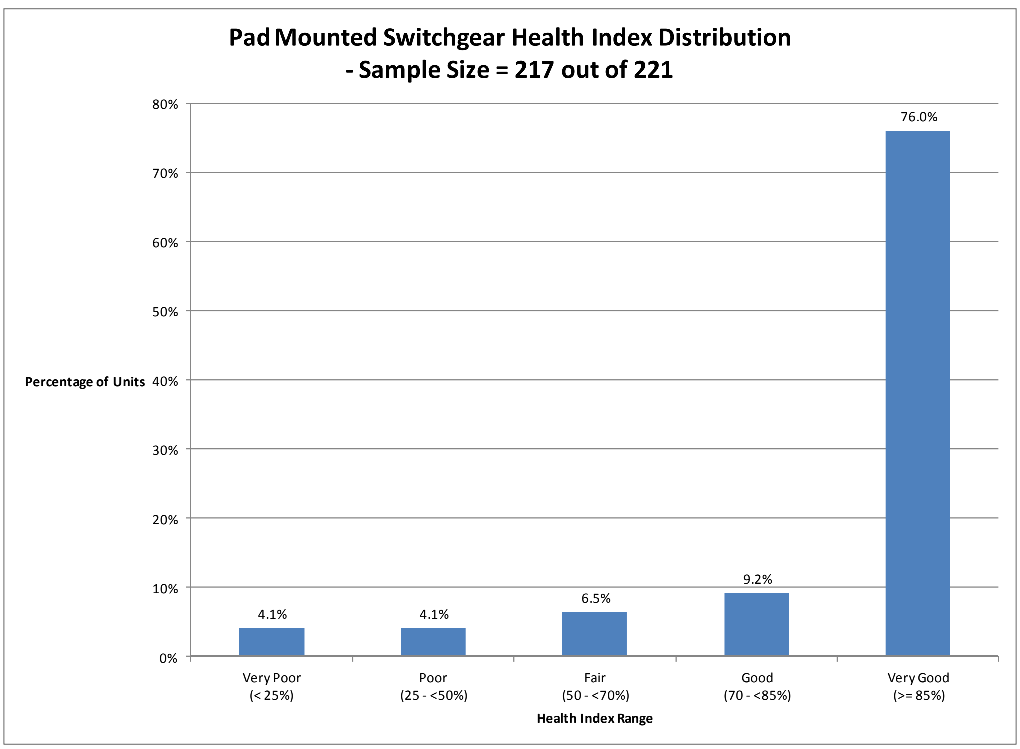

Figure 9-4 Pad Mounted Switchgear Health Index Distribution (Percentage of Units)

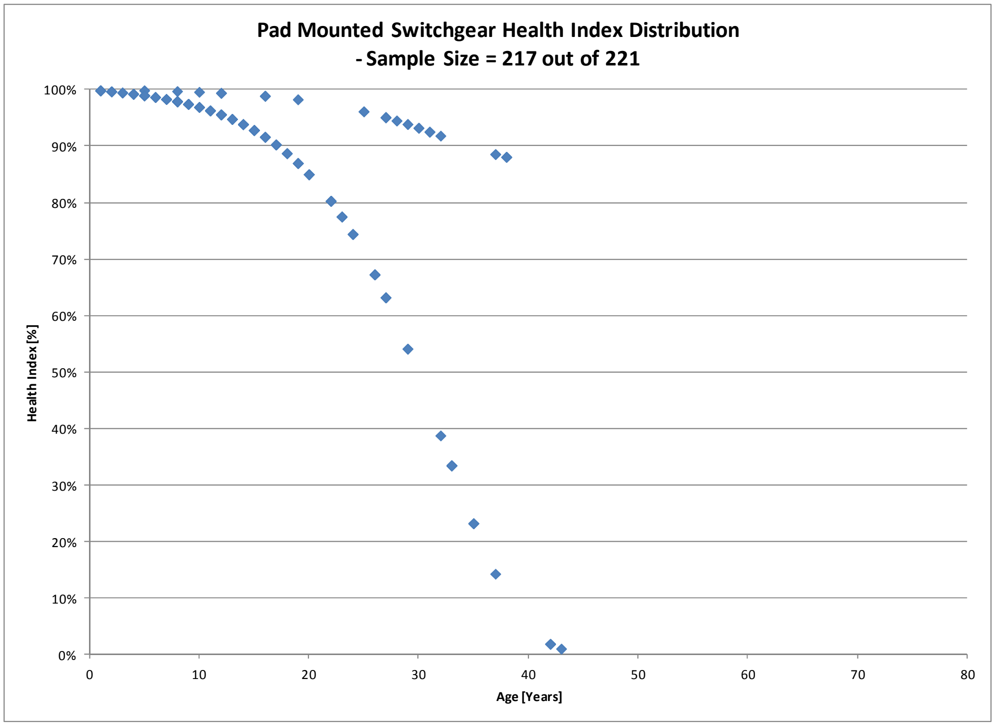

Figure 9-5 Pad Mounted Switchgear Health Index vs Age

9.5 Pad Mounted Switchgear Condition-Based Flagged-For-Action Plan

As it is assumed that Pad Mounted Switchgear is reactively replaced, the risk assessment and replacement procedure described in Section II.2.2 was applied for this asset class. This means the Flagged-For-Action Plan is based on the number of expected failures in a given year.

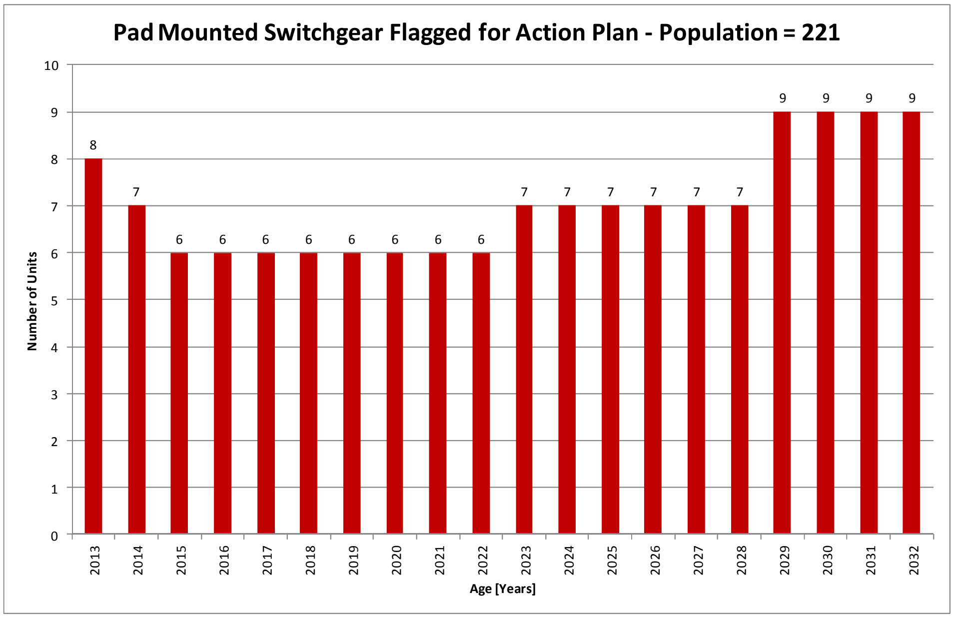

Figure 9-6 Pad Mounted Switchgear Condition-Based Flagged-For-Action Plan

9.6 Pad Mounted Switchgear Data Analysis

The data available for Pad Mounted Switchgear includes age and inspection records.

9.6.1 Pad Mounted Switchgear Data Availability Distribution

The average DAI for Pad Mounted Switchgear is 24.9%. About 86% units had age only. The status information of other condition parameters is based on VC's inspection records.

The data availability distribution for the population is shown below.

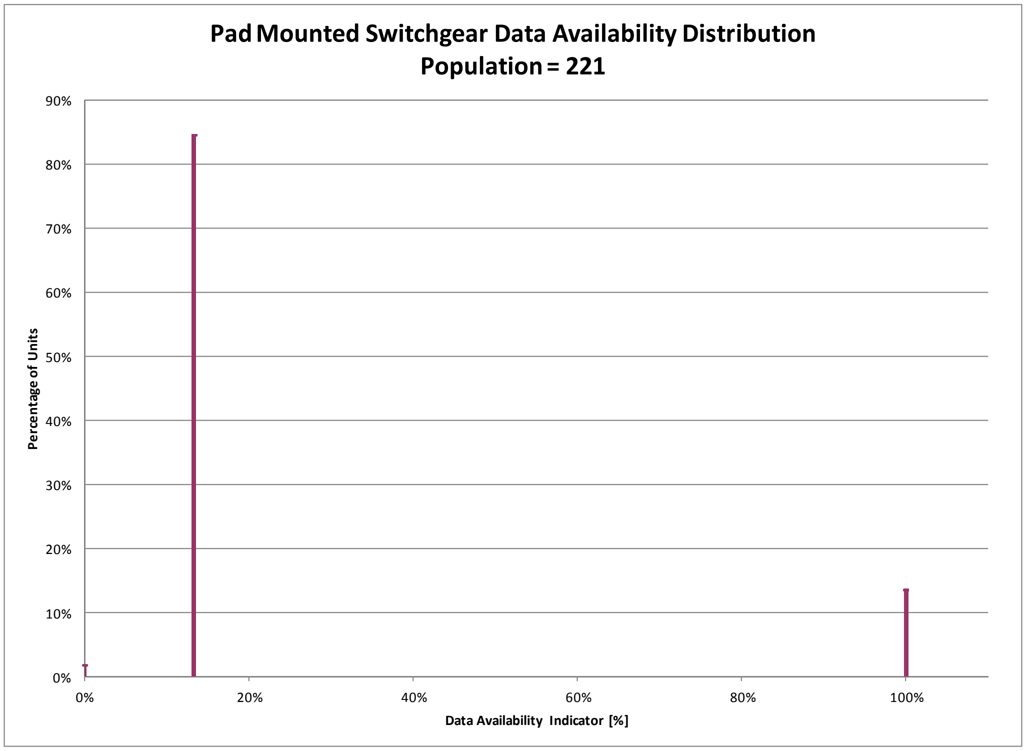

Figure 9-7 Pad Mounted Switchgear Data Availability Distribution

9.6.2 Pad Mounted Switchgear Data Gap

In this asset group, there is no major data gap. However, only a small portion of units have information other than age. It is suggested that more inspection data to be collected for the rest of population in the coming years following its inspection and maintenance cycle.

10 Underground Cables

The asset category of distribution system underground cables includes underground cross-link-polyethylene (XLPE) cables, paper insulated lead covered (PILC) cables, splices/joints, elbows, potheads and terminators at voltage levels 44 kV and below. It includes direct buried and installed-in-duct feeder cables, underground cable sections running from stations to overhead lines and from overhead lines to customer stations and switches.

The use of insulated cables on distribution feeders has virtually become a standard in most North American jurisdictions for urban residential areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental or safety reasons. The initial capital cost of a distribution underground feeder cable circuit is approximately three times the cost of an overhead line of equivalent capacity and voltage.

Distribution underground feeder cables are one of the more challenging assets for electricity systems from a condition assessment and asset management viewpoint. Underground cables are a relatively expensive asset. However, it is very difficult and therefore very expensive to obtain meaningful condition information for buried cables. Underground cable systems, unlike overhead lines, do not suffer from weather induced faults and have better reliability records.

In this study, there are three types of underground cable system:

- Primary underground cable
- Secondary underground cable
- Service underground cable

10.1Underground Cables Degradation Mechanism

Faults on underground feeder cables are usually caused by insulation failure within a localized area and when failures do occur they can be repaired at much lower cost than replacement of the entire cable. Thus, the standard approach to cable system management has been based on reliability rather than the balance between repair and replacement costs. As long as the reliability is within acceptable levels, it is virtually always cheaper to repair than replace cables.

Many utilities with high proportions of over 40 years old underground cables have concerns about reliability. Condition assessment programs enable utilities to prioritize the cable replacement programs based on available budgets.

Over the past 30 years XLPE insulated cables, due to their lower costs and easier splicing have all but replaced paper-insulated cables in new installations. The existing population of XLPE cables is still relatively young in terms of normal cable lifetimes. Therefore, failures that have occurred can be classified as early life failures. In the early days of polymeric insulated cables, their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced during manufacturing. Over the past 30 years many of these problems have been addressed, and modern XLPE cables and accessories are generally considered very reliable if manufactured and installed through competent workmanship.

Polymeric insulation is very sensitive to discharge activity, thus, cable, joints and accessories must be discharge free when installed. Water penetration into the insulation/conductor barrier, existence of impurities within the semicon layer and presence of high dielectric stress are the principal causes of insulation treeing and the most significant degradation processes for earlier generation of polymeric cables. The rate of water tree growth depends on the quality of the polymeric insulation and the manufacturing process. In addition to manufacturing improvements, development of tree retardant XLPE cables and designs with metal foil barriers and water migration controls have further reduced the rate of deterioration from treeing.

Examining recovered failed cable samples to detect and quantify treeing serves as an effective means to assess the general condition and estimate the future life of XLPE cables. Alternatively, accelerated electrical testing of recovered cables can also be used to determine condition.

Most utilities are beginning to determine the condition of their cables through lab testing and in-situ testing. In the absence of testing, the only other indicators of cable health are:

- Number of failures per unit length of installation
- Age of Cables

At this time, the precise life expectancy of XLPE cables is difficult to ascertain. There is concern that these cables will have a shorter lifetime than the earlier paper insulated cables, but experience is still limited. The life expectancy of tree-retardant (TR) XLPE cables is considered in excess of 40 years.

The major consequences of cable failure are adverse impacts on reliability. Fundamentally, end of life cannot be predicted since most insulation system failures are related to the occurrence of a transient event such as an overvoltage caused by breaker operations, lightning strikes or flashovers, etc.

10.2 Underground Cables Health Index Formulation

This section presents the Health Index Formula that was developed and used for VC Underground Cables. The Health Index equation is shown in Equation 1 of Section II.1; the condition, sub-condition parameters, weights, and condition criteria are as follows.

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

10.2.1 Underground Cables Condition and Sub-Condition Parameters

Table 10-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	CPS Lookup Table
1	Service Record	1	Table 10-2
	De-rating Factor		Table 10-3

Table 10-2 Service Record (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	CPF Lookup table	$WCPF_n$	$CPF_{n.max}$
1	Age	Figure 10-1	1	4

10.2.2 Condition Criteria

<u>Age</u>

Assume that the failure rate for Underground Cables exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

--- Primary XLPE (tree retardant direct buried/in-duct)

Assuming that at the ages of 30 and 50 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the CPF for Age is the survival curve normalized to the maximum CPF score of 4 (i.e. 4*Survival Curve). The CPF vs. Age for such cables is also shown in the figure below:

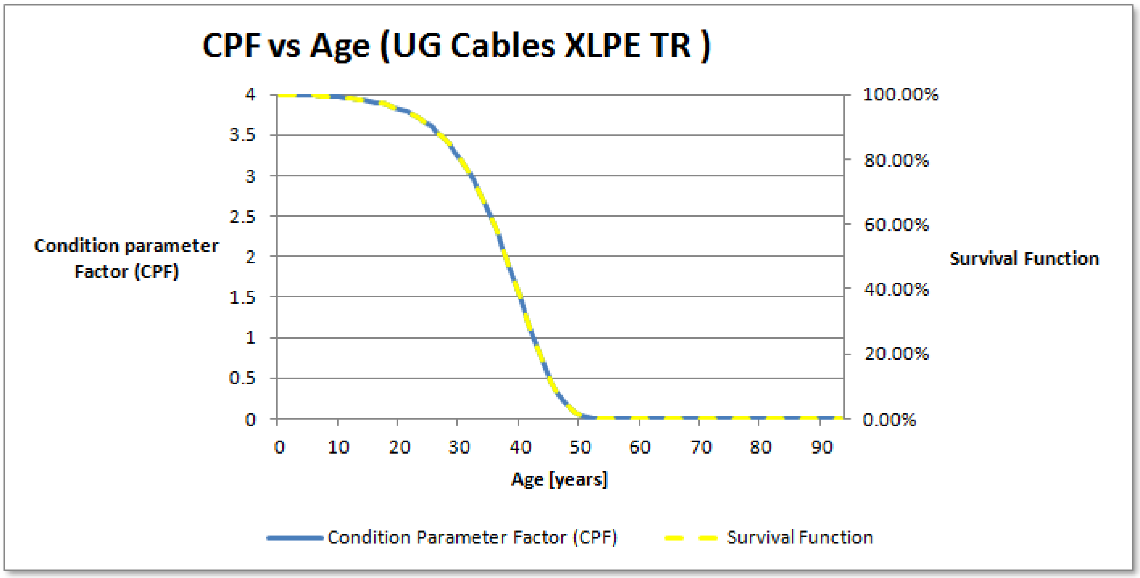

Figure 10-1 Age Condition Criteria (Underground Cables –XLPE TR)

De-Rating Factor (DRF)

De-Rating (DR) Multiplier

The de-rating is based on the following equation:

$$DR = \min(DRF_1, DRF_2, DRF_3)$$

Equation 10-1

Where DRF are as described as follows

Table 10-3 De-Rating Factors

De-Rating Factor (DRF)	De-Rating Factor	Description
DRF_1	0.8	Non tree retardant cables
DRF_2	0.8	Direct buried cables
DRF_3	Table 10-4	Yearly failure count per unit length

Table 10-4 Cable Failure Condition Criteria

De-rating	Description (failure counts/100 kM/year)
1	0
0.9	15
0.8	25
0.7	35
0.6	51

10.3 Underground Cables Age Distribution

The age distribution is shown in the figures below. Age was available for 92% of the population. The average age was found to be 20 years.

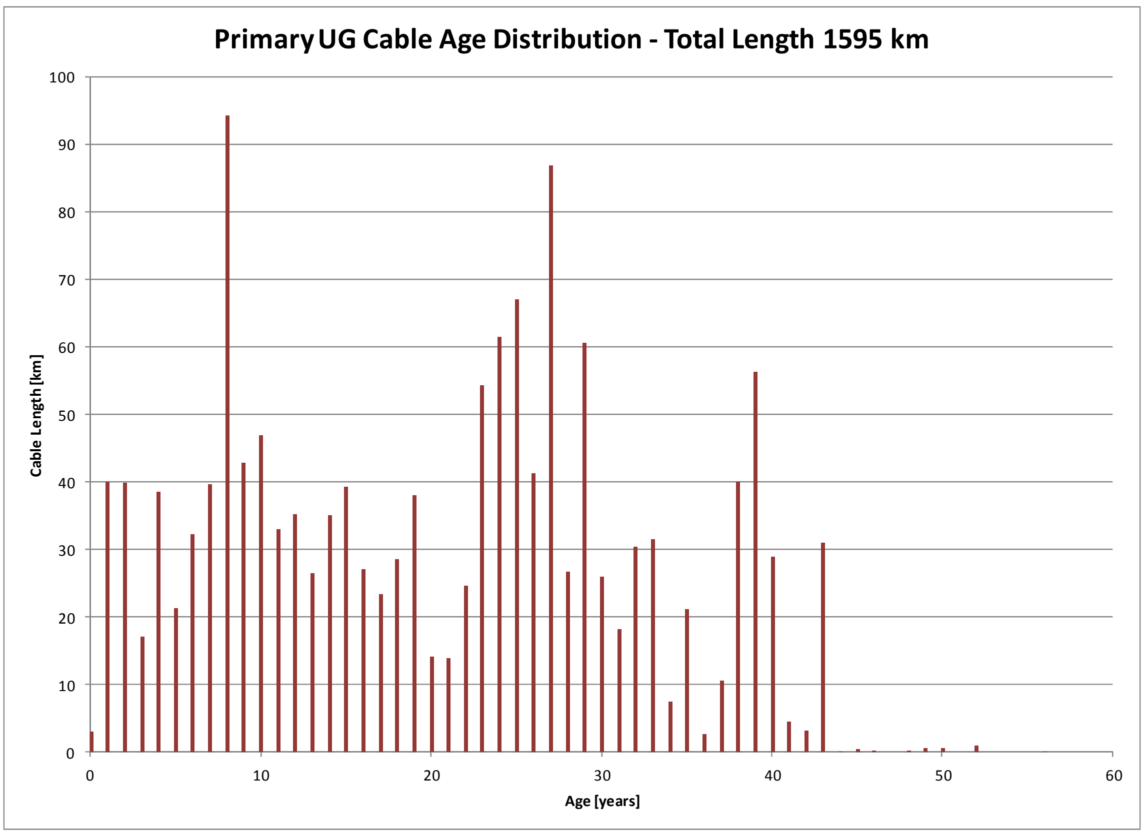

Figure 10-2 Underground Cables Age Distribution

10.4 Underground Cables Health Index Results

There are 1,595 km in-service Underground Cables at VC. The condition assessment is mainly age-driven, together with some deratings based on locations and cable types.

The average Health Index value is 76%. The Health Index Results are as follows:

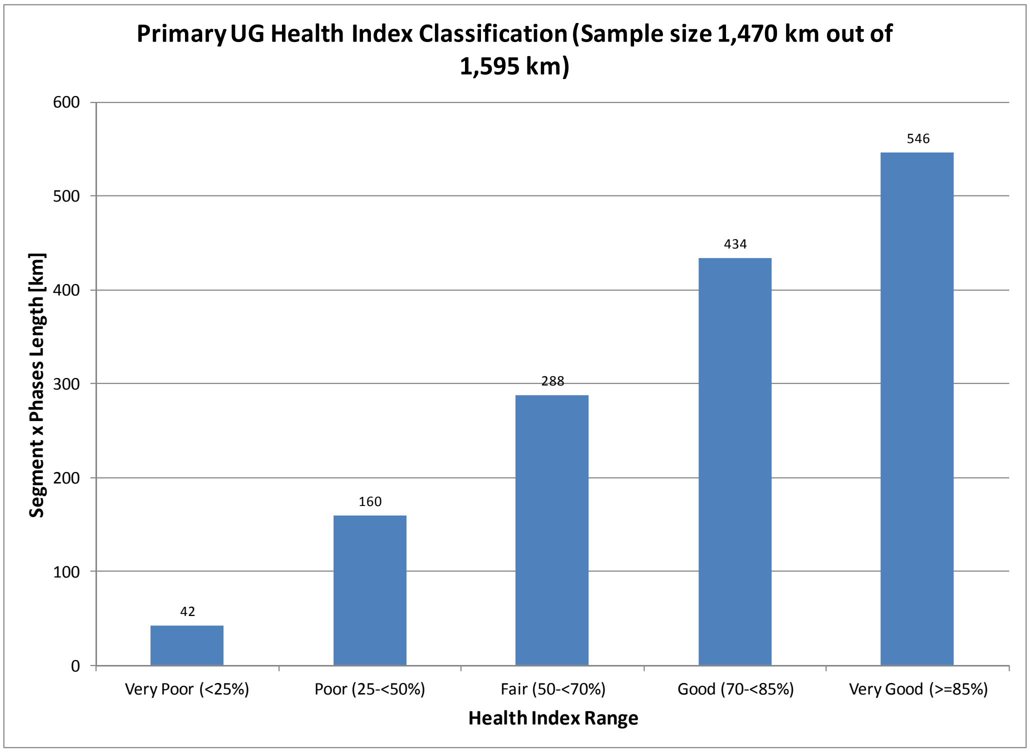

Figure 10-3 Underground Cables Health Index Distribution (Length)

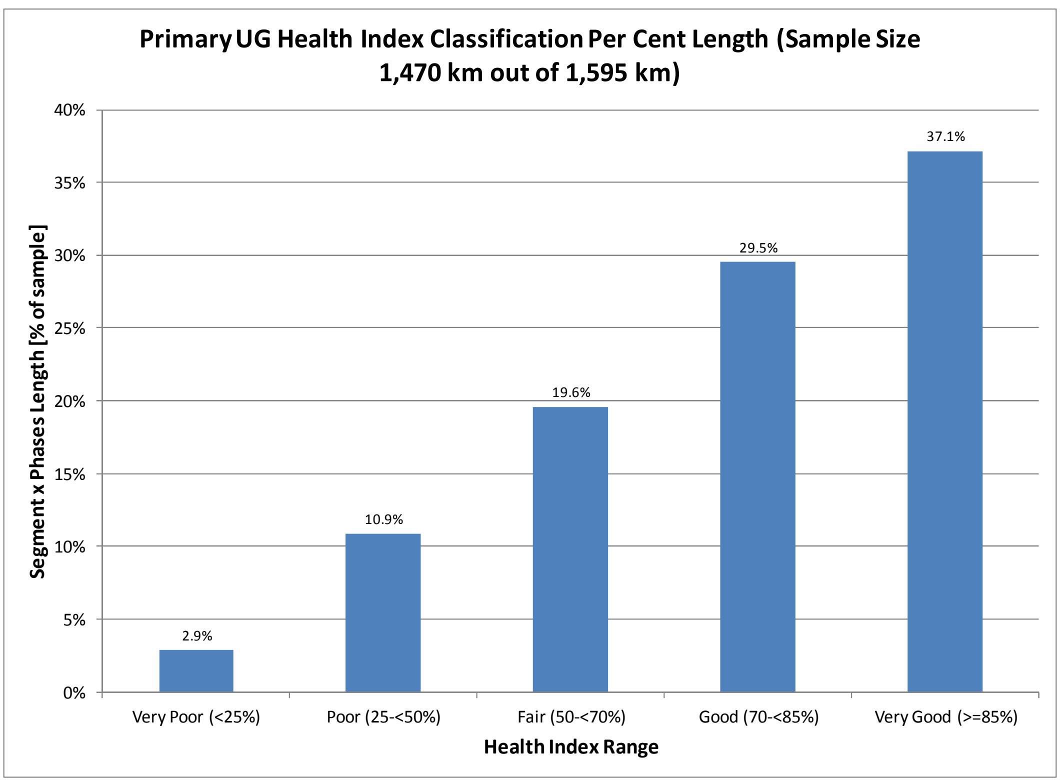

Figure 10-4 Underground Cables Health Index Distribution (Percentage)

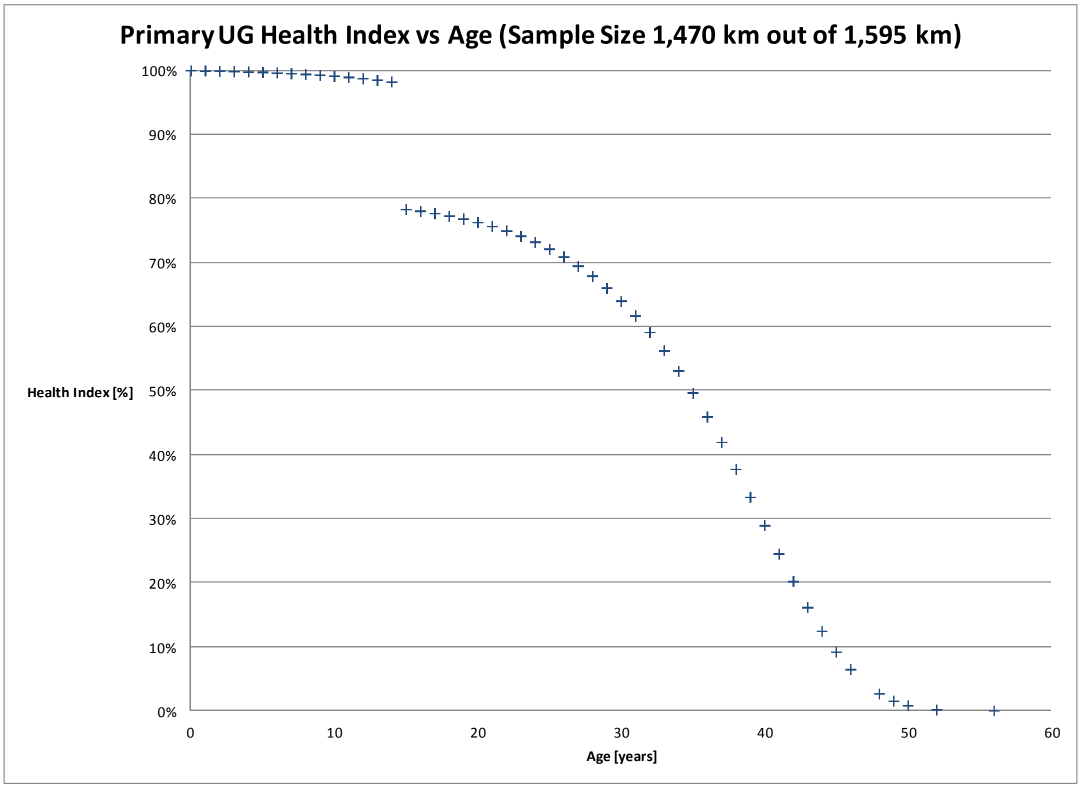

Figure 10-5 Underground Cables Health Index vs Age

10.5 Underground Cables Condition-Based Flagged-For-Action Plan

As it is assumed that Underground Cables are reactively replaced, the Flagged-For-Action Plan is based on asset failure rate f(t), as described in Section II.2.2. This means the optimal Flagged-For-Action Plan is based on the number of expected failures in a given year.

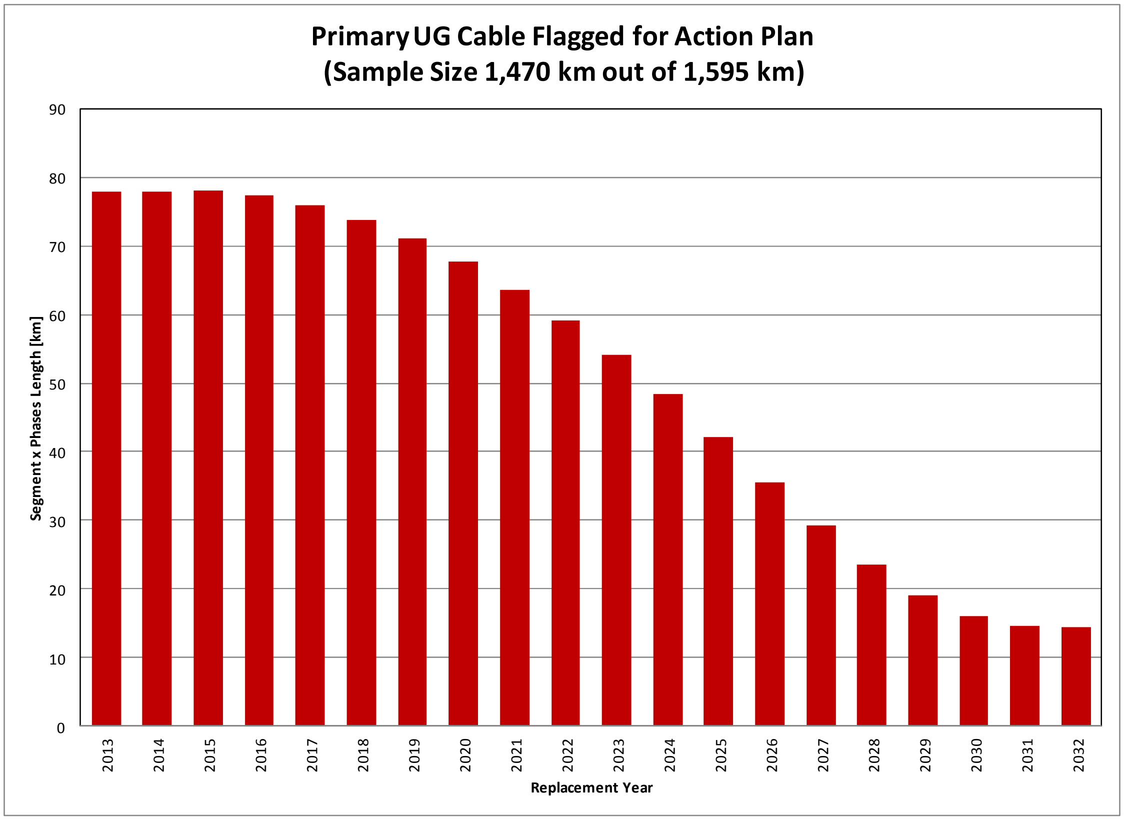

Figure 10-6 Underground Cables Condition-Based Flagged-For-Action Plan

10.6 Underground Cables Data Analysis

The data available for Underground Cables includes age and failure records.

10.6.1 Underground Cables Data Availability Distribution

In this study, age is the only information that is available to all the cable segments.

10.6.2 Underground Cables Data Gap

In this asset group, age is the only available data for most of the units. For future ACA study, some inspection maintenance records need to be collected.

The additional helpful data that can be collected are:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Cable Termination	Physical Condition	✯✯	Cable termination	Cable fault – splice installed	On-site visual inspection
Flashover	Physical Condition	✯	Cable	Cable flashover	On-site visual inspection
Loading	Service Record	✯✯	Circuit load	Monthly 15 min peak load throughout years	Operation Record

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VII REFERENCES

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VII References

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Capital Plan Summary

This section of the Distribution System Plan (DSP) is a high level summary of Veridian's capital expenditure plan.

The summary provides information on the major projects and activities that are found in Veridian's capital plan over the historic and forecast periods by category along with their drivers. The relationships between these major projects and activities, and Veridian's asset management and capital planning processes, including involvement in the Regional Planning Process, are described.

Information on customer focused activities such as Veridian's ability to connect new load and new generation customers and the impacts of customer engagement into the capital plan is provided.

Looking ahead, Veridian projects how it envisions its distribution system to develop over the next five years, and describes the way that it expects to improve operational efficiency by taking advantage of process and service innovation and technology-based opportunities.

a) Ability to Connect New Load or New Generation Customers

<u>Ability to Connect New Load</u>

Veridian's ability to connect new load is based upon its planning staff's assessment of the load forecast against the available capacity. These load versus capacity tables for the period 2007 to

2017 are available in Exhibit 2, Tab 3, Schedule 7. Please refer to Exhibit 2, Tab 3, Schedule 8 (System Planning Criteria) for specific details on the criteria.

Even though Veridian expects growth to continue in the test year, there is adequate capacity available to satisfy new load demands resulting in the System Service category being the lowest investment level of the four categories in the test year at $1.6M.

Development in the Seaton community located in north Pickering is currently underway and is expected to be a significant driver of development and new residential load customers with projected quantities of 1700 lots connected per year starting in 2015 and continuing for a number of years Based on this new load projection from the municipality, additional capacity will be required by 2018 if actual connection quantities match the projections. This additional requirement for capacity is the main driver behind the Seaton TS project targeted to be in-service for 2018. The Seaton TS project itself is projected to be a capital investment of approximately $21M in 2018. The TS project has a multi-year timeline from concept through to in-service. Veridian is currently developing a build or buy business case for the TS. The environmental assessment and the land purchase for the TS currently have a placeholder in the 2015 capital expenditure plan pending the result of the business case. New feeder construction projects extending into the Seaton community are included in the capital investment plan for 2014 through 2018. Based on this new load projection, additional capacity and distribution feeder infrastructure will be required prior to 2018 if actual connection quantities match the projections. The new feeder infrastructure is included in the 2014 capital expenditure plan as well as in subsequent year plans, to continue from their present endpoint in Ajax and extend into the Seaton Community in Pickering. These feeders once completed will bring available capacity from the existing Whitby TS to fully utilize that TS asset as well as satisfy capacity needs until the Seaton TS described below enters service.

Ability to Connect New Generation

Veridian has completed an extensive review of its distribution system for the purpose of determining the need for capital investments to accommodate the connection of REG projects. Veridian has determined, based on its experience regarding the number of applications received to date, only one distribution system expansion is required to accommodate the connection of REG projects during the test year of 2014. The particular project is for an application for a 25.012 MW generation facility for Index Energy in Ajax, scheduled for connection during 2014. Consultation with the transmitter, Hydro One, has occurred for this generator connection and a Connection Cost Agreement is currently in place with the generator, covering both Veridian and Hydro One costs associated with the connection. Veridian's distribution system can currently accommodate the remaining and forecast applications through the test year without further capital investments. It is important to note that there are system constraints to the connection of REG projects within Veridian's service territory; however those constraints are located at Hydro One owned transformer stations.

Table 1 below outlines the number of greater than 10 KW REG applications Veridian has received, prepared connection impact assessments for, and connected to its distribution system since the inception of the Feed-in-Tariff program by the Ontario Power Authority (OPA) in 2009. The table is accurate to July 31, 2013 and the number of applications and connected kilowatts has been confirmed with the OPA.

Table 1 – FIT Information – Veridian – 2009 to July 31, 2013

FIT	Connected	kW	Applications	kW	CIA Issued	kW
2009	0		8	26798	0	
2010	0		11	2564	3	976
2011	3	341	0	0	7	36082
2012	2	619	0	0	4	690
2013	3	590	15	2991	4	1260

The numbers in Table 1 indicates a greater quantity of Customer Impact Assessments (CIAs) issued versus applications received by Veridian. This anomaly occurred as a result of a generator application to Hydro One for a REG that will be embedded on Veridian's distribution system. Veridian was required to complete a CIA for the project; however the application for connection was made to Hydro One. The REG is 10 MW in size and is referred to as the Penn Energy project. There are connection costs associated with the REG, which will be recovered from Hydro One and ultimately the generator; however there is no expansion work required for Veridian's distribution system to accommodate the REG.

b) Annual Capital Expenditures by Investment Category

Table 2 provides the total annual capital expenditures by investment category over the historic period 2009 to 2012 including the projected expenditures in the 2013 bridge year.
Table 3 provides the total annual capital expenditures by investment category over the forecast period 2014 to 2018.

Please refer to Exhibit 2, Tab 3, Schedule 10, Attachment 1, Appendix 2-AB for further details.
Tables 2 and 3 are excerpts from Appendix 2-AB.

Table 2 – Total Annual Capital Expenditures by Category (Historic)

Bridge Year: 2013

CATEGORY	Historic Period (actual)				
	2009	2010	2011	2012	2013
	Actual	Actual	Actual	Actual	Actual
	$ '000				
System Access	3,836	6,670	9,475	20,246	17,769
System Renewal	5,106	3,003	2,499	6,418	6,215
System Service	6,995	3,681	7,644	6,992	5,937
General Plant	3,656	9,829	6,805	6,501	3,289
TOTAL EXPENDITURE	19,593	23,184	26,423	40,156	33,210

Table 3 – Total Annual Capital Expenditures by Category (Forecast)

First year of Forecast Period: 2014

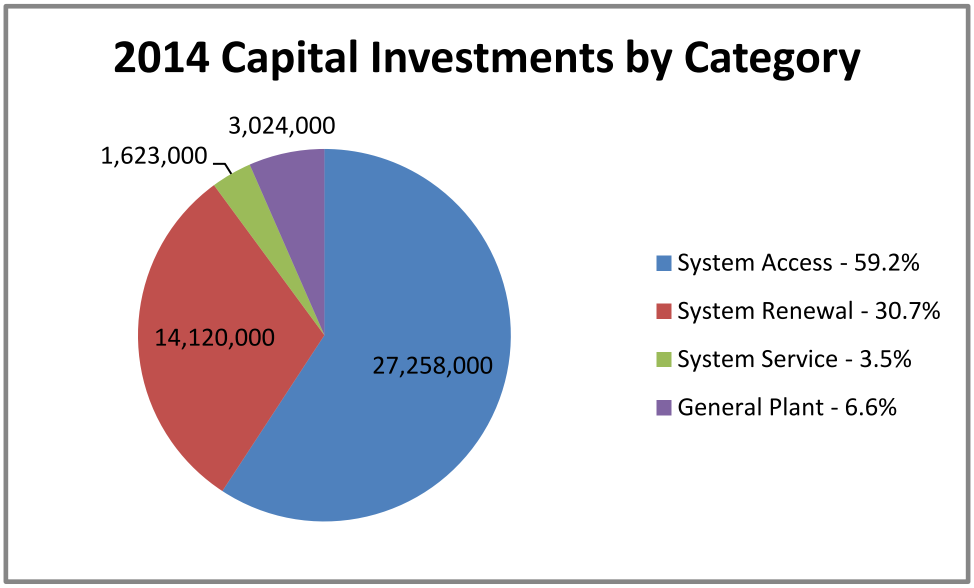
CATEGORY	**Forecast Period** (planned)				
	2014	**2015**	**2016**	**2017**	**2018**
	$ '000				
System Access	27,258	13,315	15,869	11,323	34,018
System Renewal	14,120	14,372	11,441	12,527	10,117
System Service	1,623	63	275	1,013	-
General Plant	3,024	4,515	3,676	2,943	2,650
TOTAL EXPENDITURE	46,025	32,264	31,261	27,805	46,785

c) Investment Categories

The following will be a brief descriptions of each investment category found within Veridian's capital expenditure plan including how the asset management and capital planning process have affected the expenditures within each category.

Chart 1 provides the allocation by investment category in dollars and contributing percentage to Veridian's capital expenditure plan in the 2014 test year.

Chart 1 – 2014 Capital Expenditure Plan by Investment Category



System Access

These project and activity investments are driven by statutory, regulatory or other obligations on the part of Veridian to provide customers with access to its distribution system and are deemed as non-discretionary projects. The scheduling of the project in terms of when the project is planned to start as well as when it is expected to be completed is usually controlled by the third party. Veridian makes best efforts to accommodate the third party in meeting its timelines.

Blocks of projects within in this category which are included in Veridian's test year capital expenditure plan are: new residential subdivisions, commercial, institutional, and industrial (general service) customers, municipal, regional and provincial road relocations, long term load transfer eliminations, and metering.

At this time, the outputs from the asset management process are strictly related to the condition of the existing distribution assets. All of the above noted projects will trigger a review of the assets involved. Veridian reviews the current condition of the asset as well as the projected remaining life of the asset and makes a decision whether or not to replace at the time of the project. For example, a pole that is considered as a three-phase riser for a new general service customer will be reviewed whether the pole meets current design standards for pole loading, clearances, its condition and remaining life. Any future known area or road reconstruction, municipal or Veridian, will also be considered in the decision whether to replace the pole at this time. The pole is replaced, at Veridian's expense, if any of the reviews yield a positive response and based on the best available information at the time to reasonably suit both present and future needs.

Assets involved with road relocation projects are typically removed from service prior to the end of their service life and new assets are installed. Some assets may be returned to Veridian's stores inventory to be re-used but only after they pass appropriate tests confirming that they are acceptable to be safely re-used. The latter is a requirement of the Equipment Approval Section 6 in the Ontario Regulation 22/04 Electrical Distribution Safety, which is a mandatory requirement that all Ontario distributors must comply with.

Outputs from the capital expenditure process identify these projects as consistently occurring year to year. Quantities will vary based on the current economic conditions, or upon location within the distributor's service area as growth and development vary between Veridian's operating districts. Please refer to Exhibit 2, Tab 3, Schedule 5, for details regarding Veridian's distinct non-contiguous districts. Overall, Veridian expects an increase in these types of projects based on improving economic conditions and this is reflected in the capital expenditure plan. Veridian's Capital Investment Process (CIP) as described in Exhibit 2, Tab 3, Schedule 4, has not been used to rank, score and prioritize these candidate capital projects as they are non-discretionary.

In the test year, System Access projects total $27.3M and represent 59.2% of the capital spend within the capital expenditure plan.

Please refer to Exhibit 2, Tab 3, Schedule 12, Attachment 1 for a list of material capital projects in the 2014 test year.

System Renewal

These project and activity investments involve replacing and/or refurbishing distribution assets to extend the original service life of the assets and thereby maintain the ability of Veridian's distribution system to provide customers with electricity services. They have been deemed as non-discretionary projects.

Blocks of projects within this category which are included in Veridian's test year capital expenditure plan include the planned and unplanned sustainment projects.

Veridian will continue to maintain a reactive program of unplanned sustainment to replace the assets that actually do fail, or those that need to be replaced due to their poor condition, before they fail or if they pose a safety risk to the public or workers. The latter group are identified through inspections and preventative maintenance activities such as visual inspections, infra-red surveys and dry ice cleaning. Additional activities such as insulator washing, adding polymeric lightning arrestors, installing animal guards, etc., will also ensure that the asset can remain in service for the expected number of years or longer with an increased level of reliability expected.

Please refer to Exhibit 2, Tab 3, Schedule 12, Attachment 1 for a list of material capital projects.

At this time, the outputs from the asset management process are the staff adjusted results of the Asset Condition Assessment (ACA) completed in 2013. Based on the ACA, the long-term plan for such assets is based on the failure rate particular to each asset category with the expectation that some of the units will fail prior to their typical end-of-life (EOL) and some will continue to operate beyond their EOL. To that end, Veridian has implemented an ongoing proactive program of planned sustainment to replace an identified quantity of these assets before they fail. The proactive program not only allows Veridian to better plan for future replacements, it avoids a future bow wave of replacements, thereby smoothing financial impacts year over year as well as mitigating reliability problems by eliminating the assets most likely to fail sooner rather than when they actually fail. Prior to the test year, and the completion of the ACA, Veridian had a proactive program of planned sustainment to replace the assets in the substation transformers, substation breakers, wood pole, pad mounted switchgear and underground primary cable categories. In the test year, the pole mounted, pad mounted, submersible and vault transformer, and overhead switch asset categories have been included to further take advantage of the benefits realized from its current proactive programs.

The planned sustainment programs within the System Renewal category are based on major asset categories assessed in the ACA. Please refer to Exhibit 2, Tab 3, Schedule 12, Attachment 1 for a list of material capital projects in the System Renewal category.

The Asset Management Plan (AMP) to be developed is described in Exhibit 2, Tab 3, Schedule 4.

Veridian's Capital Investment Process (CIP) as described in Exhibit 2, Tab 3, Schedule 4, has not been used to rank, score and prioritize these candidate capital projects as they are non-discretionary.

Outputs from the capital expenditure process identify these projects as consistently occurring year to year with quantities varying based on refining the results of the ACA and the development of the AMP.

Veridian has identified two major focus points that lay within the System Renewal envelope:

- Asset Management Process; and
- Municipal Substations.

First, to emphasize the criticality of improving the overall asset management process, Veridian is augmenting staff resources within the Planning & Maintenance Department (described in this Rate Application), that will concentrate on developing the entire asset management process as described above in brief and in more detail in Exhibit 2, Tab 3, Schedule 4. Simultaneously, Veridian has increased capital investment in planned sustainment across multiple asset categories from the ACA results, starting in the test year's capital expenditure plan

Second, and related to the first, Veridian's municipal substations in whole, have been identified as being the single most critical asset within its distribution system. Due to its non-contiguous service area, Veridian is required to operate a higher number of substations than most distributors, which in turn means a higher number of substation assets to be maintained, repaired, replaced or refurbished. This identified criticality and the numbers involved, has driven the requirement for increased capital investment in this asset category and the necessity for dedicated resources to address the ACA results.

In the test year, System Renewal projects total $14.1M and represent 30.7% of the capital spend within the capital expenditure plan.

System Service

These project and activity investments are modifications to Veridian's distribution system to ensure that the system continues to meet Veridian's operational objectives while addressing anticipated future customer electricity service requirements and can be either discretionary or non-discretionary projects.

Blocks of projects within this category which are included in Veridian's test year capital expenditure plan associated with system capacity. As noted previously in this document, Veridian is satisfied based on the analysis of its available capacity and load projected, that there is ample capacity available to satisfy new load demands.

At this time, the outputs from the asset management process are strictly related to the condition of the existing distribution assets as outlined in the Service Access section above.

Veridian's Capital Investment Process (CIP) as described in Exhibit 2, Tab 3, Schedule 4, has been used to rank, score and prioritize these candidate capital projects if they are deemed to be discretionary.

Outputs from the capital expenditure process identify when these projects are required based on Veridian's load forecasts and capital planning criteria as found in Exhibit 2, Tab 3, Schedule 8.

In the test year, System Service projects total $1.6M and represent 3.5% of the capital spend within the capital expenditure plan.

Please refer to Exhibit 2, Tab 3, Schedule 12, Attachment 1 for a list of significant capital projects in the 2014 test year.

General Plant

These project and activity investments are modifications, replacements or additions to Veridian's distribution assets which are not part of its distribution system and have been deemed as discretionary projects.

Blocks of projects included in this category which are included in Veridian's test year capital expenditure plan are: facilities improvements and enhancement, tools and equipment, fleet, and information technologies (IT) which are used to support day to day business and operations activities, as well as process improvements.

At this time, the outputs from the asset management process are strictly related to the condition of the existing distribution assets and do not include the general plant assets in this category.

Veridian's Capital Investment Process (CIP) as described in Exhibit 2, Tab 3, Schedule 4, has not been used to rank, score and prioritize these candidate capital projects as individual project business cases support their inclusion in the test year capital expenditure plan.

Outputs from the capital expenditure process identify these projects as consistently occurring year to year with quantities varying based on identified needs from the different Veridian business units.

In the test year, General Plant projects total $3.0M and represent 6.6% of the capital spend within the capital expenditure plan.

Please refer to Exhibit 2, Tab 3, Schedule 12, Attachment 1 for a list of significant capital projects in the 2014 test year.

d) Total Capital Cost of Material Capital Projects by Category

Please refer to Exhibit 2, Tab 3, Schedule 7, Attachment 1 .Schedule of Total Dollar of Test Year Capital Investments within Category.

e) Regional Planning Process Impacts

Please refer to Exhibit 2, Tab 3, Schedule 2, for details on Coordinated Planning with Third Parties.

f) Customer Engagement Activities

Veridian employs a variety of communications channels to solicit customer and stakeholder feedback on its business operations and then incorporate them into the capital expenditure plan. Valuable information on customer/stakeholder preferences, issues and business plans is secured through these channels, and this information informs the development of Veridian's own business initiatives.

Customers are engaged through:

- Customer Opinion Surveys;
- Gravenhurst Advisory Committee;
- Key Account Representatives;
- Municipal Utility Coordinating Committees;
- Special Purpose Community Meetings; and
- Business Associations/Community Events.

Please refer to Exhibit 1, Tab 2, Schedule 1, for additional details on customer engagement.

Other stakeholders engaged are:

- OPA;
- Transmitter (Hydro One); and
- Other Distributors.

Please refer to Exhibit 2, Tab 3, Schedule 2, for additional details on coordination with third parties.

The most significant impact from customer feedback to Veridian's capital expenditure plan is that received through the Municipal Utility Coordinating Committee meetings. Veridian has been actively pursuing this avenue of communication withal its communities throughout its service area, and makes best efforts to plan and coordinate Veridian's own capital projects with those of other parties.

Direct customer feedback received at a lower level is most often related to project design and construction activities such as: preferred location of assets such as pad mounted switchgear and transformers (where these will be placed in relation to a homeowner's driveway, window, or landscaping), driveway and boulevard restoration, etc. These are incorporated or resolved wherever they apply in the project process such as in the design stage or during the construction stage if possible.

Regardless of how received, and at what staff level, Veridian considers all feedback from customers on their own merits and makes any adjustments to its plans accordingly if possible.

g) Development of Veridian's Distribution System Over the Next 5 Years

Load and Customer Growth

It is expected that the operational and service requirements driving Veridian's capital expenditures, and found within its Distribution System Plan (DSP), will generally remain consistent through the 2014 to 2018 planning window. The projected expenditures for the test year, and going forward, not only reflect the typical spending needs of a distribution electric utility serving a growing customer base with a geographically distributed, and a diverse collection of physical assets but also include the ongoing planned capital sustainment investments required to replace the aging assets found in its distribution system.

As noted previously, growth occurs at different rates among Veridian's five operating districts. It is expected that the Ajax, Belleville and Clarington districts will continue to see fast growth as it relates to the other districts, as expansion pushes out and further develops out into the GTA. Slow to little growth is expected in the Brock and Gravenhurst districts. The Seaton community as described above is the single most significant growth area expected to develop in the foreseeable future. The extension of Highway #407 from its current end point at Brock Road in Pickering to Highway #115/35 is planned in 2015. This extension, located to the north of the Seaton community, is currently underway and is expected to initiate the development of employment lands on either side in north Pickering as it has on the sections of Highway #407 further west. Only very preliminary internal discussion has been held regarding the proposed North Pickering Airport which is located north of Highway # 407. Veridian's system planning staff has already identified a long term servicing plan for the Seaton community and for the development lands expected on either side of Highway #407.

Distribution Automation (Smart Grid) Development

Over the next 5 years, Veridian will continue to expand the automation capabilities of its distribution system. This includes projects such as the SCADA replacement described in this Cost of Service Rate Application, the ongoing capital program to replace electro-mechanical relays with electronic relays at substations, the installation of a communication platform that provides a low latency high-bandwidth capability for smart grid device communications, and the addition of distribution management to the base SCADA platform. Veridian envisions that the smart grid will develop through a combination of specific device and software installations coupled with embedding a smarter approach to distribution systems in the regular system planning and specifying of distribution system components. To achieve this vision, Veridian is augmenting resources for this emerging area of development that will be responsible for, among other items, the identification and pilot phase testing of smart grid devices and components. Once the benefit to the distribution system and customers is proven through the pilot test phase, the successful devices and components become main stream for system planners to include in their regular designs. Veridian believes this is a prudent and cost-effective process for ensuring the successful development of a smarter grid.

Accommodation of Forecasted REG projects

The prioritization process for REG expansions is the same as for distribution system expansion projects where the REG expansion is triggered and driven by customer requirements.

As previously stated, Veridian's distribution system currently has capacity to connect REG projects through the 2014 Test Year, without the necessity of expanding its distribution system, with the exception of the non-utility owned Index Energy project, which has been described previously in Exhibit 2, Tab 3, Schedule 10.

h) Distribution System Opportunities

Veridian believes that it has incorporated any known and identified customer preferences through the feedback it has received from the communication channels that it maintains as described previously. Please refer to Exhibit 1, Tab 2, Schedule 1, for additional details.

As part of its continuous improvement philosophy, Veridian has endeavoured to leverage the benefits of technology to improve operational efficiencies and the management of its assets. Additionally, Veridian considers and reviews innovative products, processes or services on an ongoing basis, and if applicable, either includes these for a specific project, or incorporates them within projects going forward based on the review during the development of the scope for the candidate projects.

- SCADA,
- Mobile Computing/Data Acquisition,
- Distribution Automation Enhancements,
- GIS Enhancement,
- Engineering/GIS Integration.

<u>SCADA</u>

Veridian is planning to add distribution management system functionality to the base SCADA platform being replaced during the 2013 bridge year and as described in this Rate Application. This functionality will allow Veridian to model its distribution system dynamically in real-time and introduce self-healing networks controlled from a central location rather than distributed on the distribution system. Please refer to Exhibit 2, Tab 3, Schedule 17, for further details on this project.

Mobile Computing/Data Acquisition (GIS Programming Enhancements)

Veridian is planning to continue the expansion of the use of its GIS across the organization through the continued roll-out of mobile computing and web-based products. The same geographic information will be available to customers in a web-based application designed to provide information on power outages and estimated restoration times. The continued expansion of the system at Veridian in the test year and beyond, following the successful completion of the pilot in 2012 is targeting to further capture the efficiencies of replacing paper-based asset data gathering capture techniques. This project is directly linked and integral in obtaining additional asset condition information for Veridian's ongoing ACA. The project includes further deployment of the devices for asset field inspections and expanding the system to include capturing information for all new distribution system equipment installations and replacements. Please refer to Exhibit 2, Tab 3, Schedule 17, for further details on this project.

Distribution Automation Enhancements

Veridian is planning to conduct a smart transformer pilot whereby a smart meter is placed in a distribution transformer and a real-time communication link created between the transformer and the System Control Centre (SCC). The addition of the meter and communication device is intended to minimally increase the cost of the transformer with these features. If successful, the smart transformer will communicate outages to the SCC in real-time, provide overload notification for loads such as electric vehicles and provide opportunity to detect theft of power.

GIS Enhancement

Veridian is planning to continue the expansion of the use of geographic information across the organization through the continued roll-out of mobile computing and web-based products. The same geographic information will be available to customers in a web-based application designed to provide information on power outages and estimated restoration times.

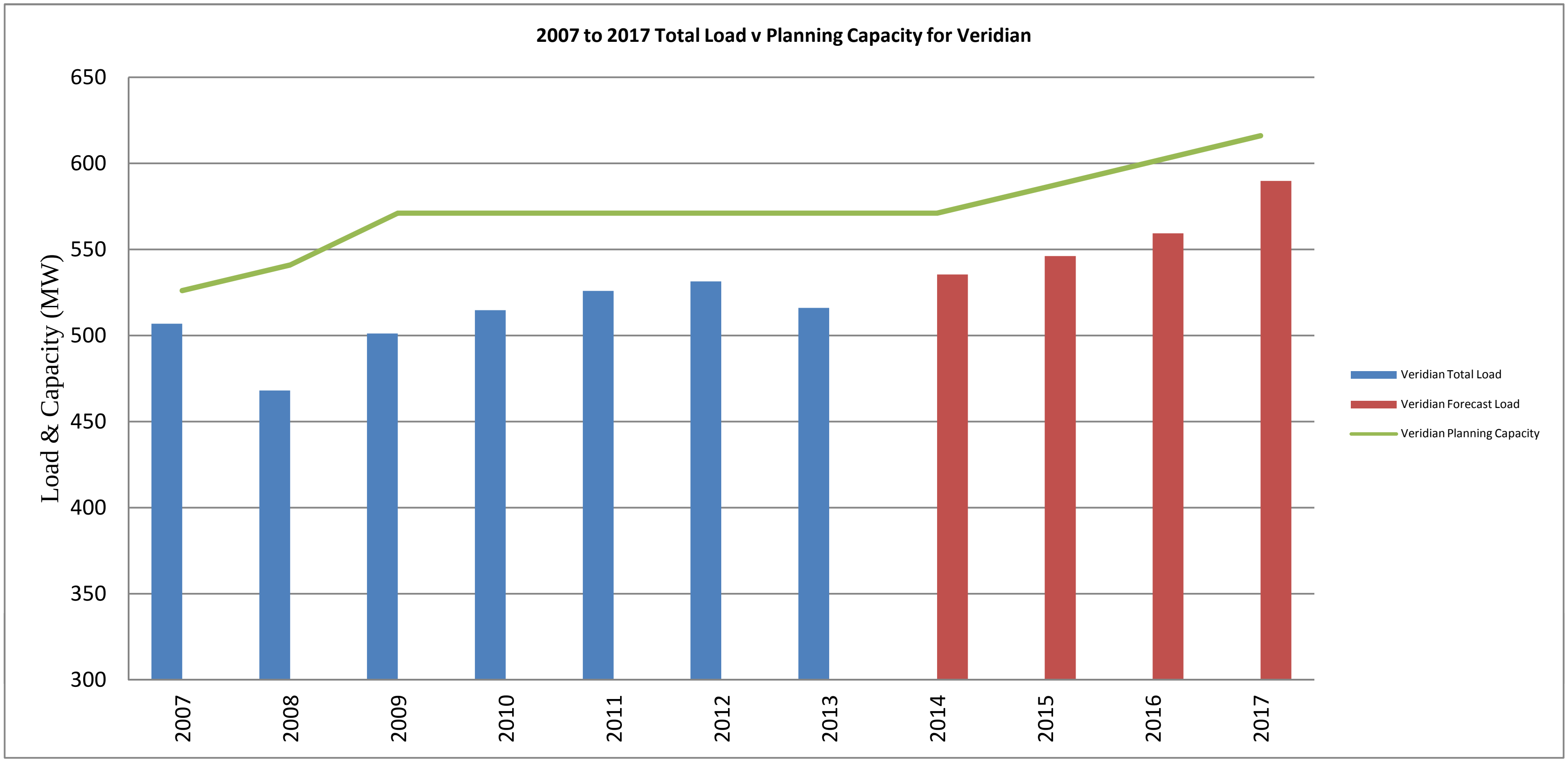
Veridian is proposing to conduct a micro-grid demonstration pilot as part of this Rate Application. The project would include the installation of a renewable generator, coupled with an energy storage device and management system, a grid supply of electricity and a load in the form of an electric vehicle charger. This project is intended to provide insight and learning to micro-grids in general and specifically the facilitation of additional renewable generation on distribution systems through the use of energy storage devices. Please refer to Exhibit 2, Tab 3, Schedule 17, for further details on this projects.

Engineering/GIS Integration

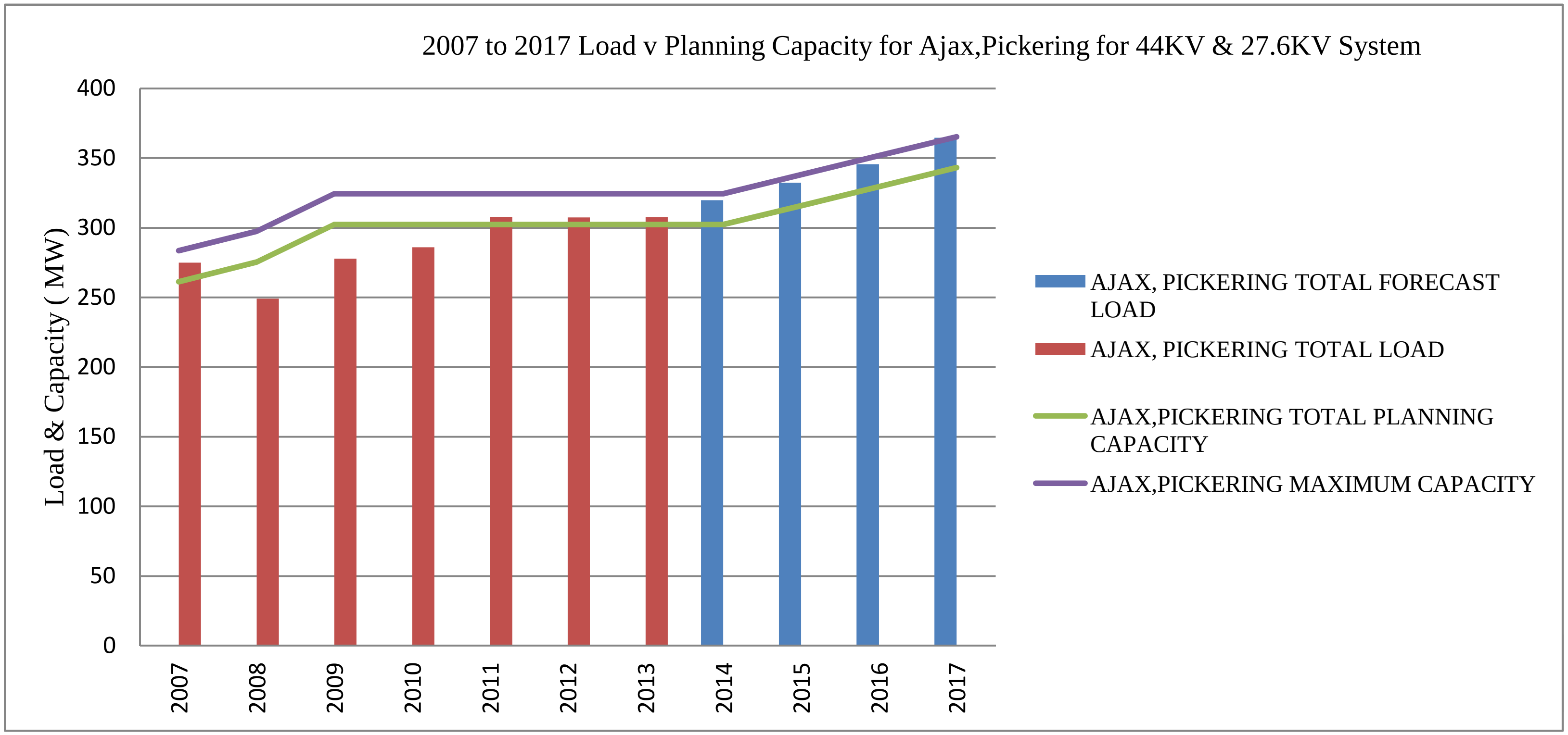
Veridian is continuing to work on and is taking steps to improve the integration between its Engineering department and the Operational Information Systems (OIS) department so that engineering design drawings are able to slide seamlessly back and forth between the two departments. The expected cost savings is through minimizing the labour cost and time needed to re-draw and modify drawings by the OIS staff before they can be inserted into the GIS system. The Engineering staff will save labour cost and time by being able to start capital project base plans from a "cut out" section of the GIS, which can then be easily "pasted" back with little or no additional manipulation back into the GIS. Please refer to Exhibit 2, Tab 3, Schedule 17, for further details on this project.

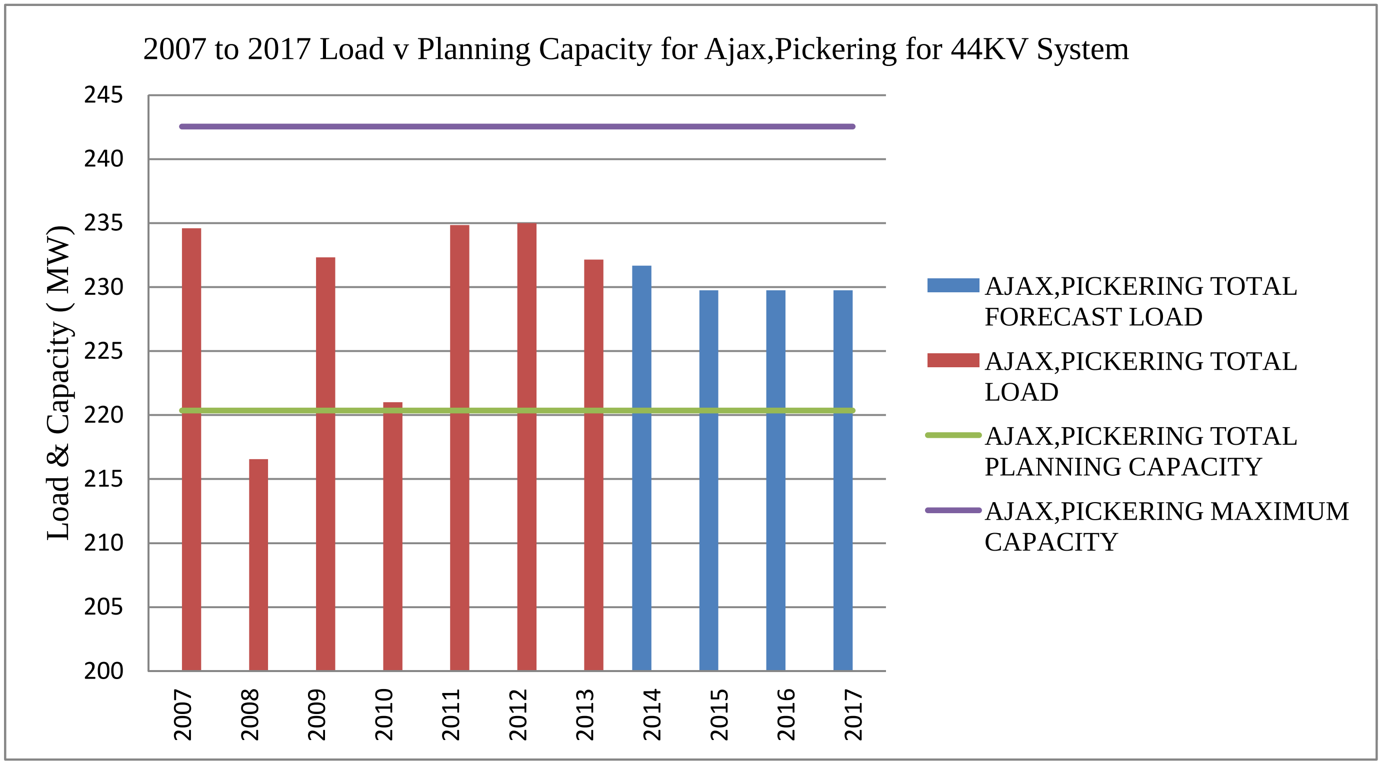
Attachment 1 of 1

System Loading

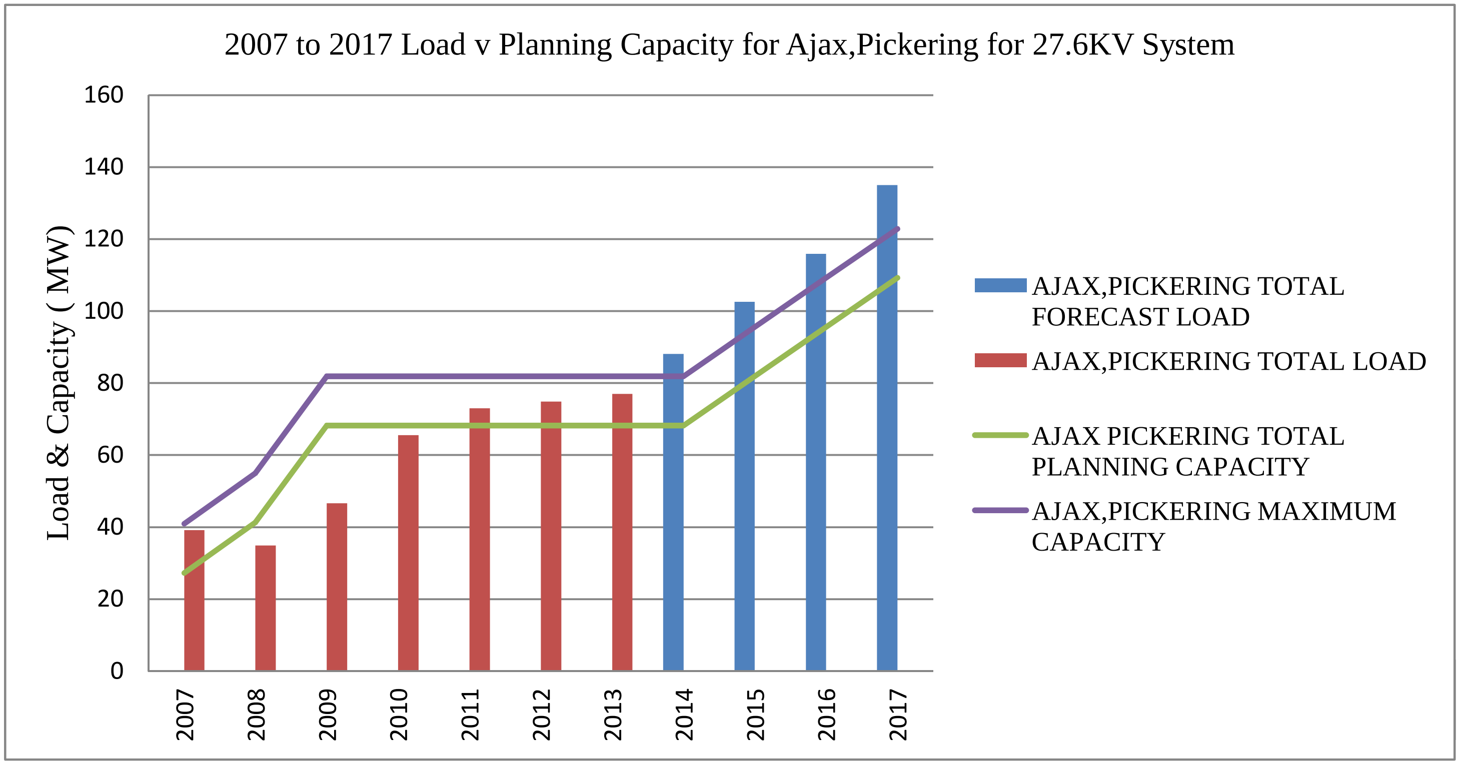


2007 to 2017 Total Load v Planning Capacity for Veridian
Load & Capacity (MW)
650
600
550
500
450
400
350
300
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Veridian Total Load
Veridian Forecast Load
Veridian Planning Capacity

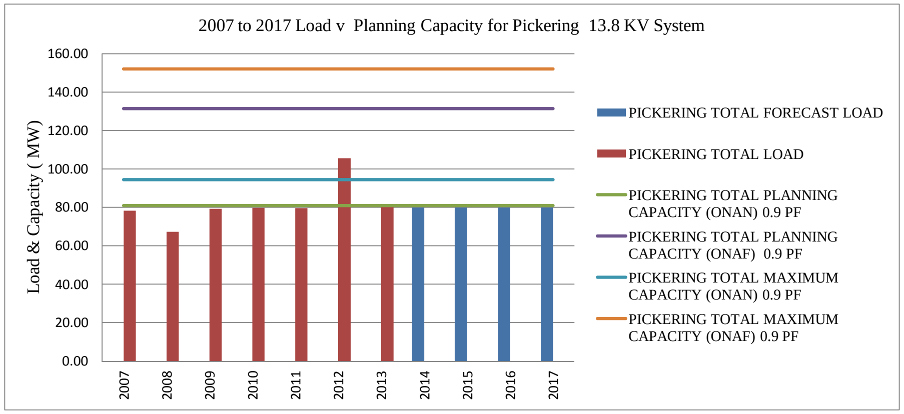

2007 to 2017 Load v Planning Capacity for Ajax,Pickering for 44KV & 27.6KV System
Load & Capacity (MW)
0
50
100
150
200
250
300
350
400
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
AJAX, PICKERING TOTAL FORECAST LOAD
AJAX, PICKERING TOTAL LOAD
AJAX,PICKERING TOTAL PLANNING CAPACITY
AJAX,PICKERING MAXIMUM CAPACITY

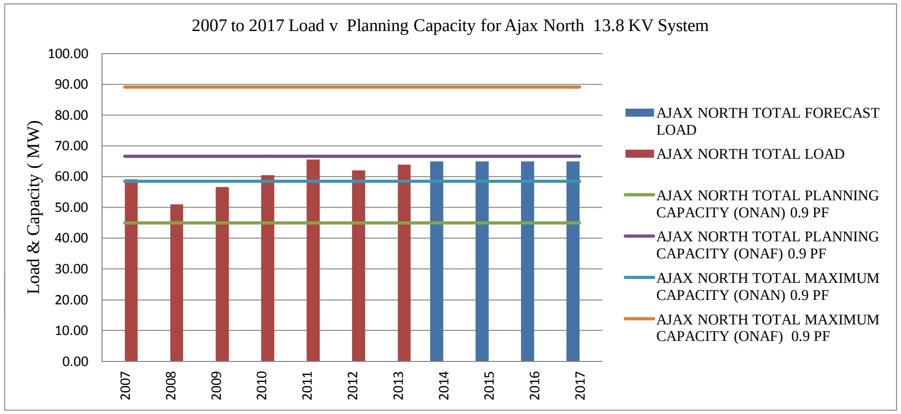


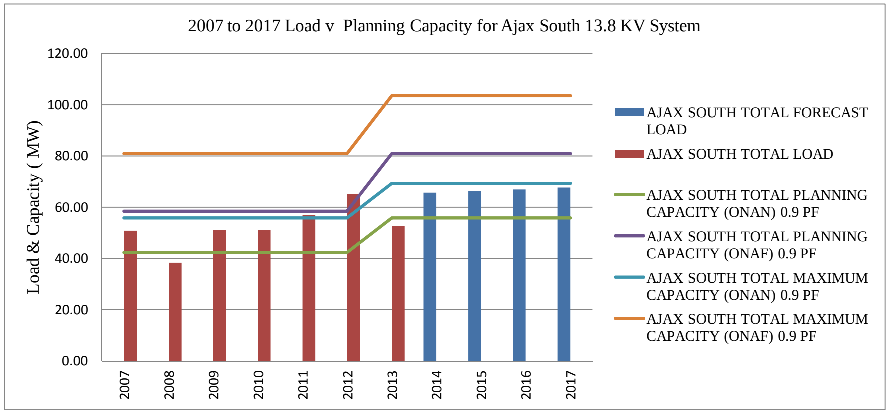
2007 to 2017 Load v Planning Capacity for Ajax,Pickering for 44KV System
Load & Capacity (MW)
245
240
235
230
225
220
215
210
205
200
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
AJAX,PICKERING TOTAL FORECAST LOAD
AJAX,PICKERING TOTAL LOAD
AJAX,PICKERING TOTAL PLANNING CAPACITY
AJAX,PICKERING MAXIMUM CAPACITY

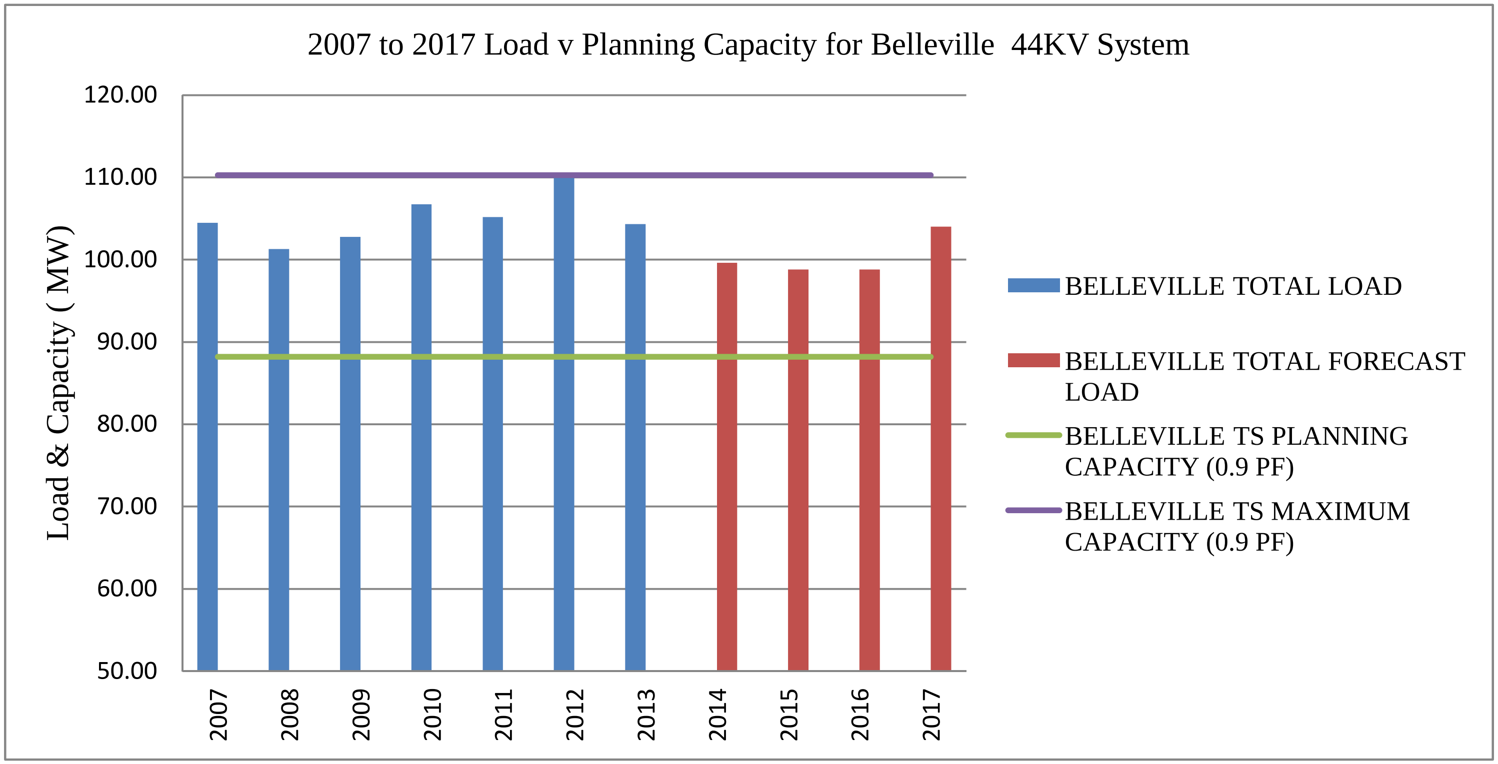


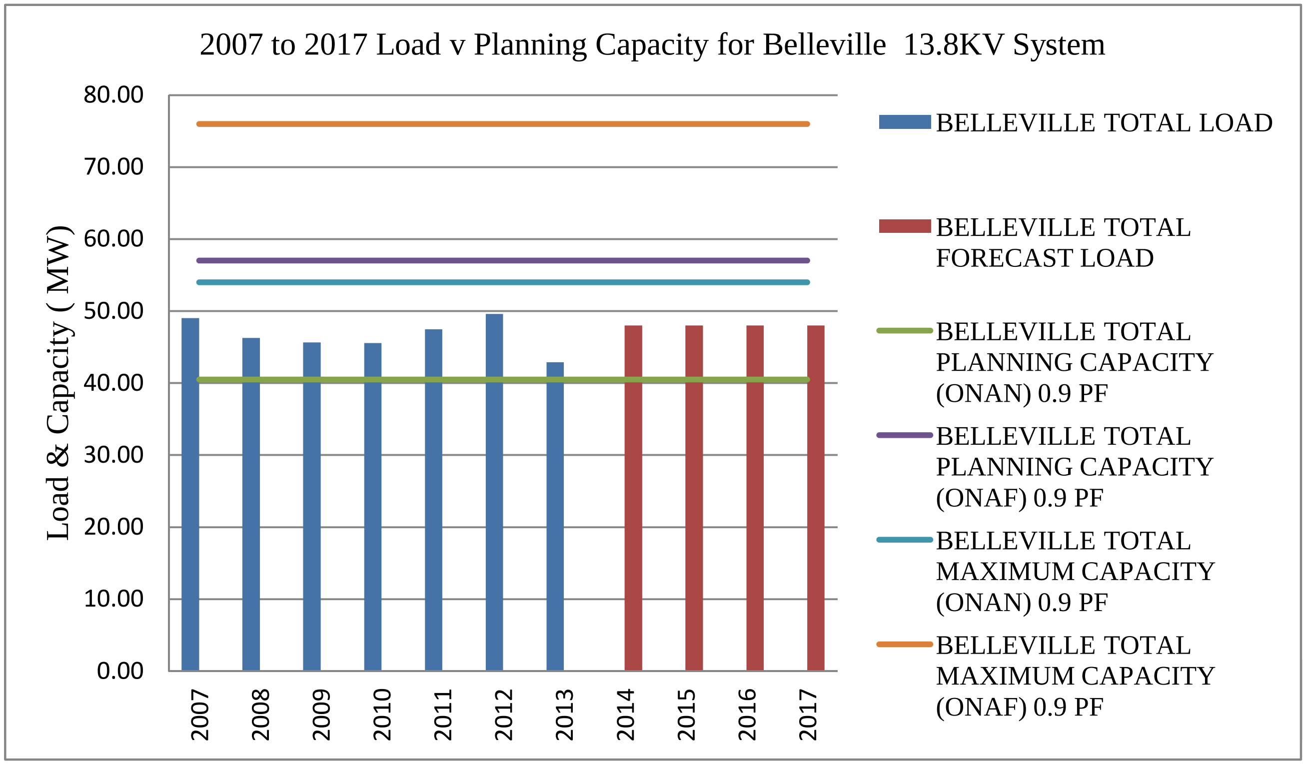
2007 to 2017 Load v Planning Capacity for Ajax,Pickering for 27.6KV System
Load & Capacity (MW)
160
140
120
100
80
60
40
20
0
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
AJAX,PICKERING TOTAL FORECAST LOAD
AJAX,PICKERING TOTAL LOAD
AJAX PICKERING TOTAL PLANNING CAPACITY
AJAX,PICKERING MAXIMUM CAPACITY

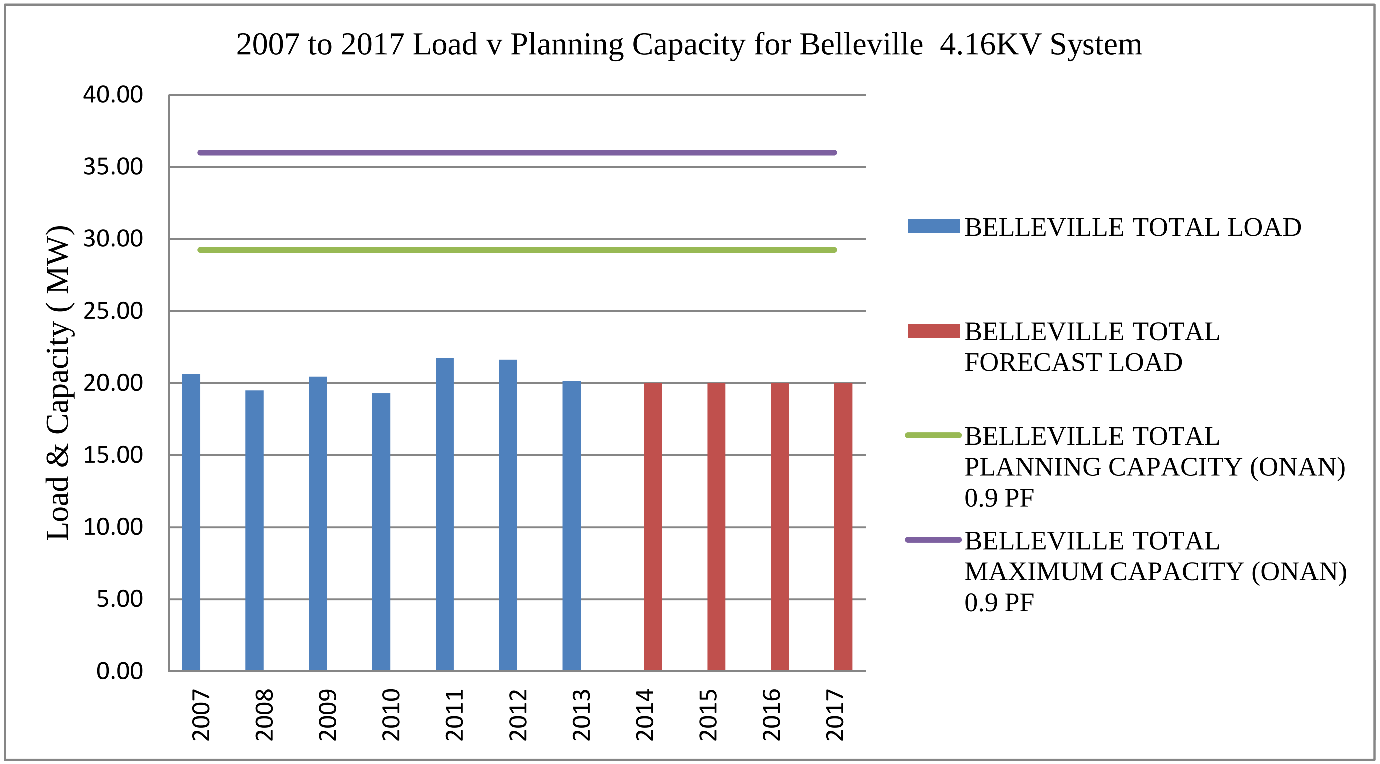

2007 to 2017 Load v Planning Capacity for Pickering 13.8 KV System
Load & Capacity (MW)
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
PICKERING TOTAL FORECAST LOAD
PICKERING TOTAL LOAD
PICKERING TOTAL PLANNING CAPACITY (ONAN) 0.9 PF
PICKERING TOTAL PLANNING CAPACITY (ONAF) 0.9 PF
PICKERING TOTAL MAXIMUM CAPACITY (ONAN) 0.9 PF
PICKERING TOTAL MAXIMUM CAPACITY (ONAF) 0.9 PF

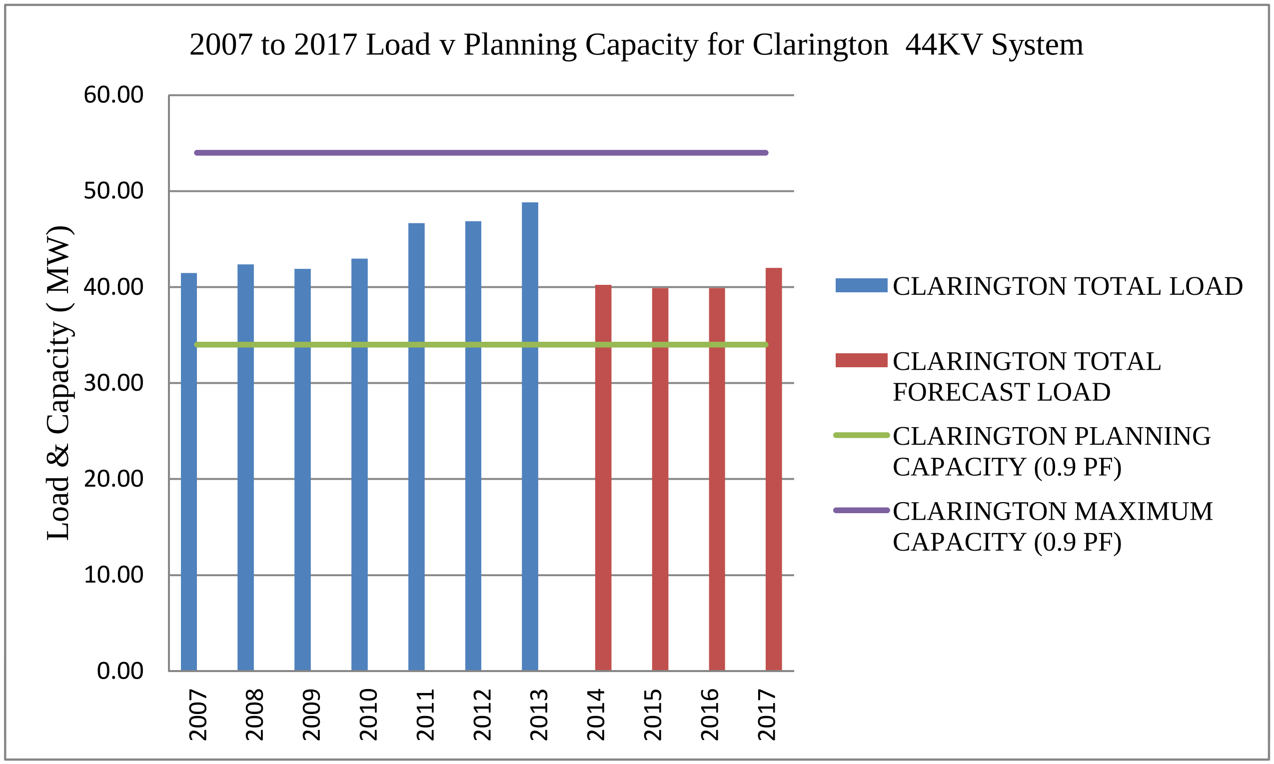

2007 to 2017 Load v Planning Capacity for Ajax North 13.8 KV System
Load & Capacity (MW)
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
AJAX NORTH TOTAL FORECAST LOAD
AJAX NORTH TOTAL LOAD
AJAX NORTH TOTAL PLANNING CAPACITY (ONAN) 0.9 PF
AJAX NORTH TOTAL PLANNING CAPACITY (ONAF) 0.9 PF
AJAX NORTH TOTAL MAXIMUM CAPACITY (ONAN) 0.9 PF
AJAX NORTH TOTAL MAXIMUM CAPACITY (ONAF) 0.9 PF

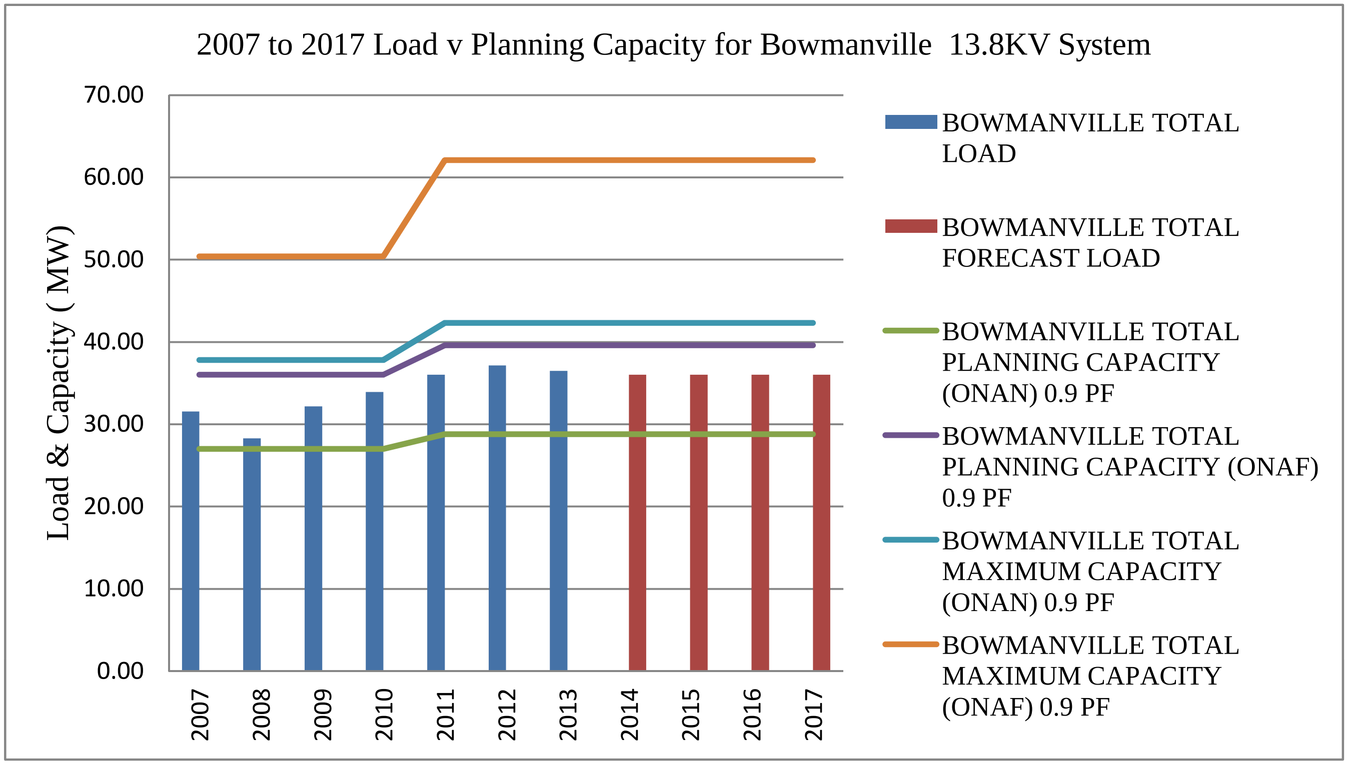

2007 to 2017 Load v Planning Capacity for Ajax South 13.8 KV System
Load & Capacity (MW)
120.00
100.00
80.00
60.00
40.00
20.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
AJAX SOUTH TOTAL FORECAST LOAD
AJAX SOUTH TOTAL LOAD
AJAX SOUTH TOTAL PLANNING CAPACITY (ONAN) 0.9 PF
AJAX SOUTH TOTAL PLANNING CAPACITY (ONAF) 0.9 PF
AJAX SOUTH TOTAL MAXIMUM CAPACITY (ONAN) 0.9 PF
AJAX SOUTH TOTAL MAXIMUM CAPACITY (ONAF) 0.9 PF


2007 to 2017 Load v Planning Capacity for Belleville 44KV System
Load & Capacity (MW)
120.00
110.00
100.00
90.00
80.00
70.00
60.00
50.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
BELLEVILLE TOTAL LOAD
BELLEVILLE TOTAL FORECAST LOAD
BELLEVILLE TS PLANNING CAPACITY (0.9 PF)
BELLEVILLE TS MAXIMUM CAPACITY (0.9 PF)

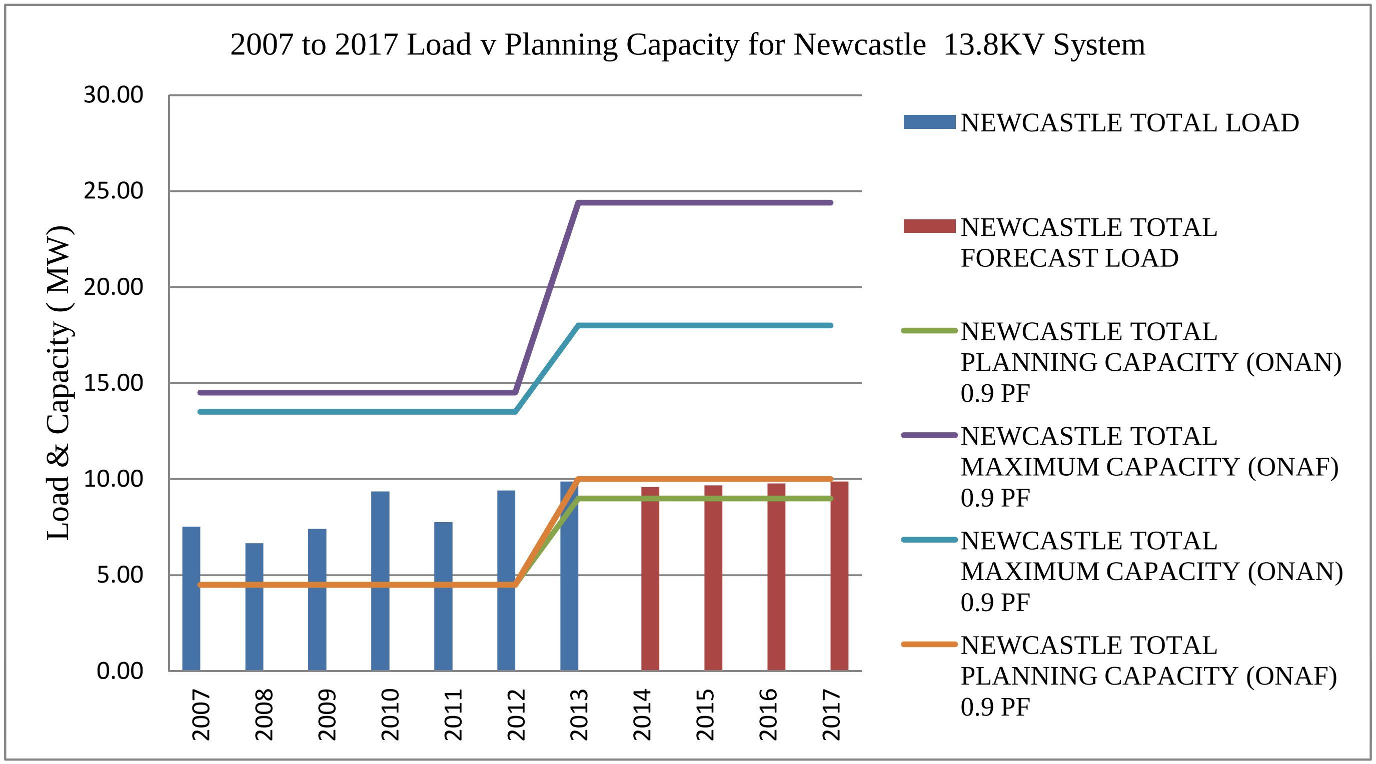

2007 to 2017 Load v Planning Capacity for Belleville 13.8KV System
Load & Capacity (MW)
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
BELLEVILLE TOTAL LOAD
BELLEVILLE TOTAL FORECAST LOAD
BELLEVILLE TOTAL PLANNING CAPACITY (ONAN) 0.9 PF
BELLEVILLE TOTAL PLANNING CAPACITY (ONAF) 0.9 PF
BELLEVILLE TOTAL MAXIMUM CAPACITY (ONAN) 0.9 PF
BELLEVILLE TOTAL MAXIMUM CAPACITY (ONAF) 0.9 PF


2007 to 2017 Load v Planning Capacity for Belleville 4.16KV System
Load & Capacity (MW)
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
BELLEVILLE TOTAL LOAD
BELLEVILLE TOTAL FORECAST LOAD
BELLEVILLE TOTAL PLANNING CAPACITY (ONAN) 0.9 PF
BELLEVILLE TOTAL MAXIMUM CAPACITY (ONAN) 0.9 PF

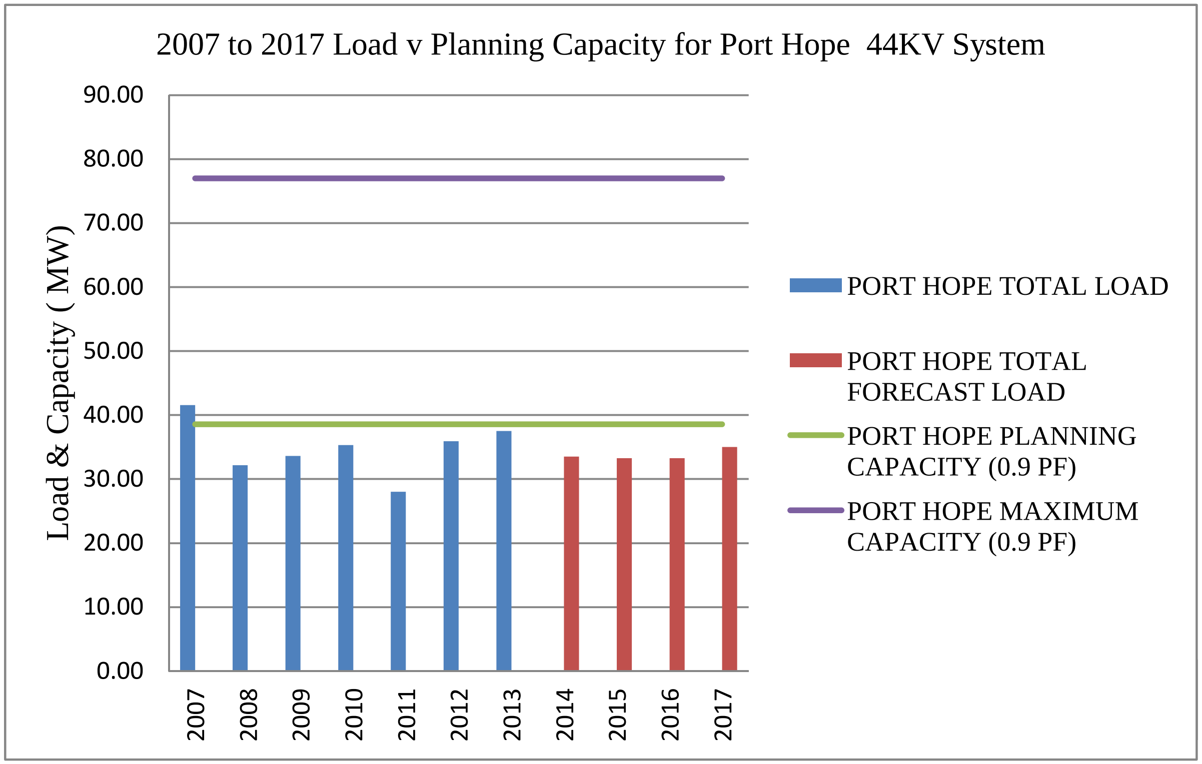

2007 to 2017 Load v Planning Capacity for Clarington 44KV System
Load & Capacity (MW)
60.00
50.00
40.00
30.00
20.00
10.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
CLARINGTON TOTAL LOAD
CLARINGTON TOTAL FORECAST LOAD
CLARINGTON PLANNING CAPACITY (0.9 PF)
CLARINGTON MAXIMUM CAPACITY (0.9 PF)

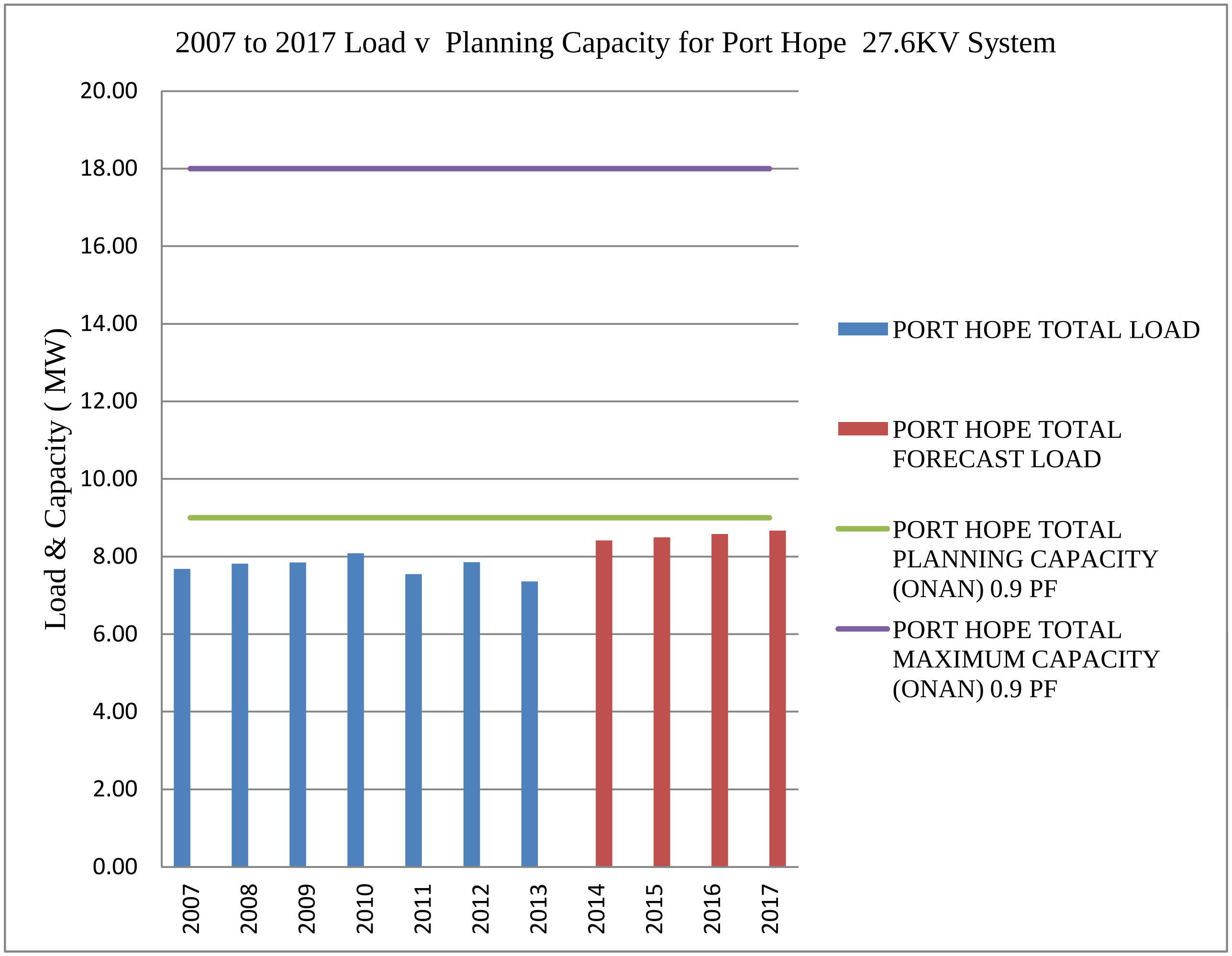


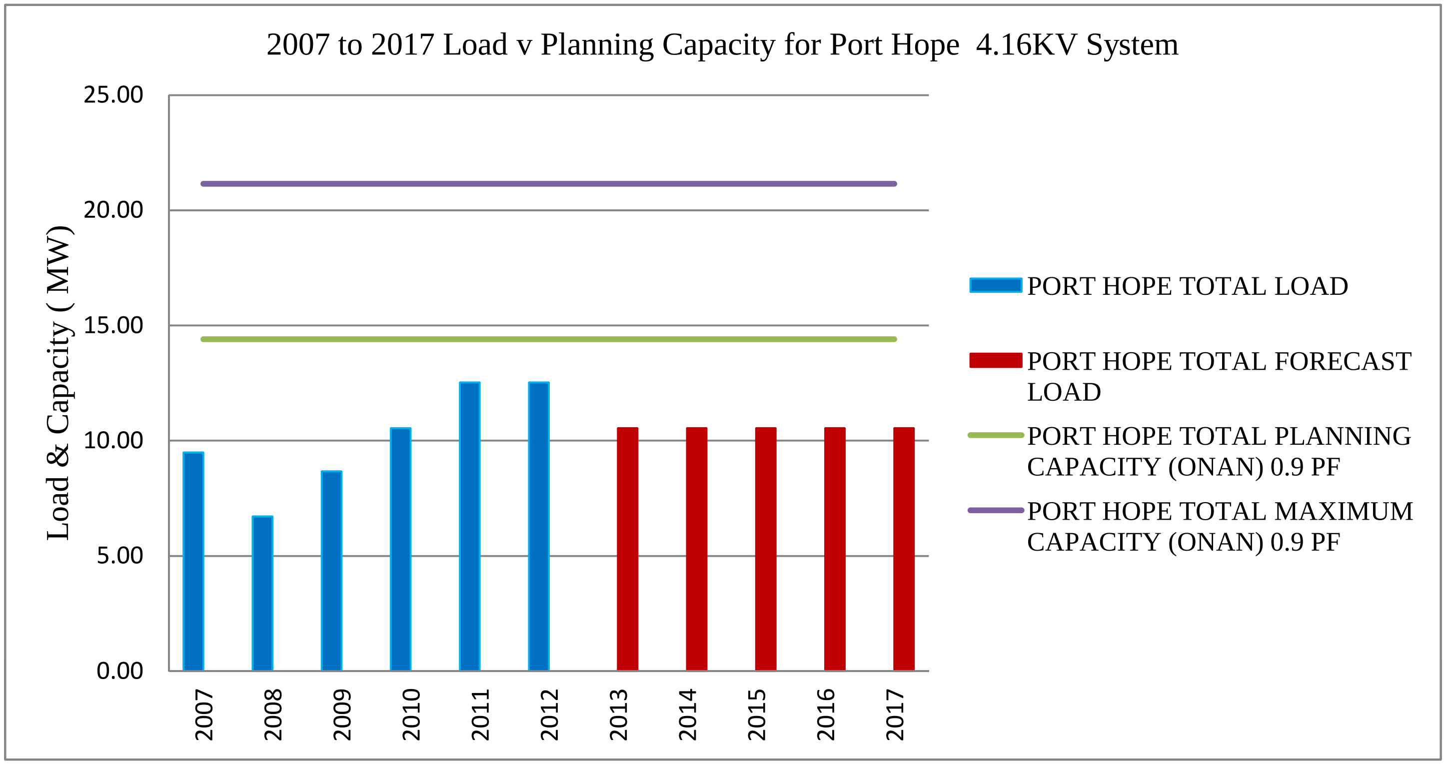
2007 to 2017 Load v Planning Capacity for Bowmanville 13.8KV System
Load & Capacity (MW)
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
BOWMANVILLE TOTAL LOAD
BOWMANVILLE TOTAL FORECAST LOAD
BOWMANVILLE TOTAL PLANNING CAPACITY (ONAN) 0.9 PF
BOWMANVILLE TOTAL PLANNING CAPACITY (ONAF) 0.9 PF
BOWMANVILLE TOTAL MAXIMUM CAPACITY (ONAN) 0.9 PF
BOWMANVILLE TOTAL MAXIMUM CAPACITY (ONAF) 0.9 PF

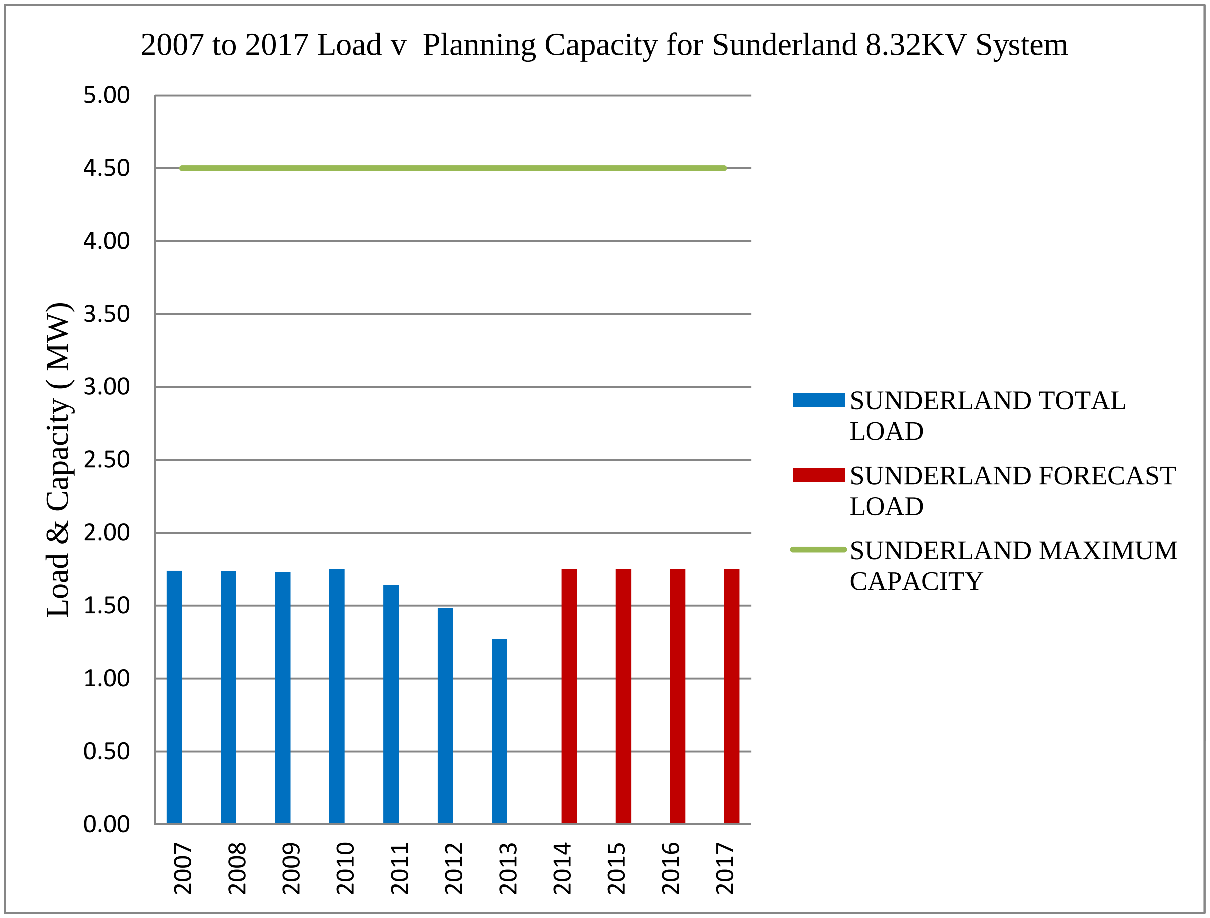


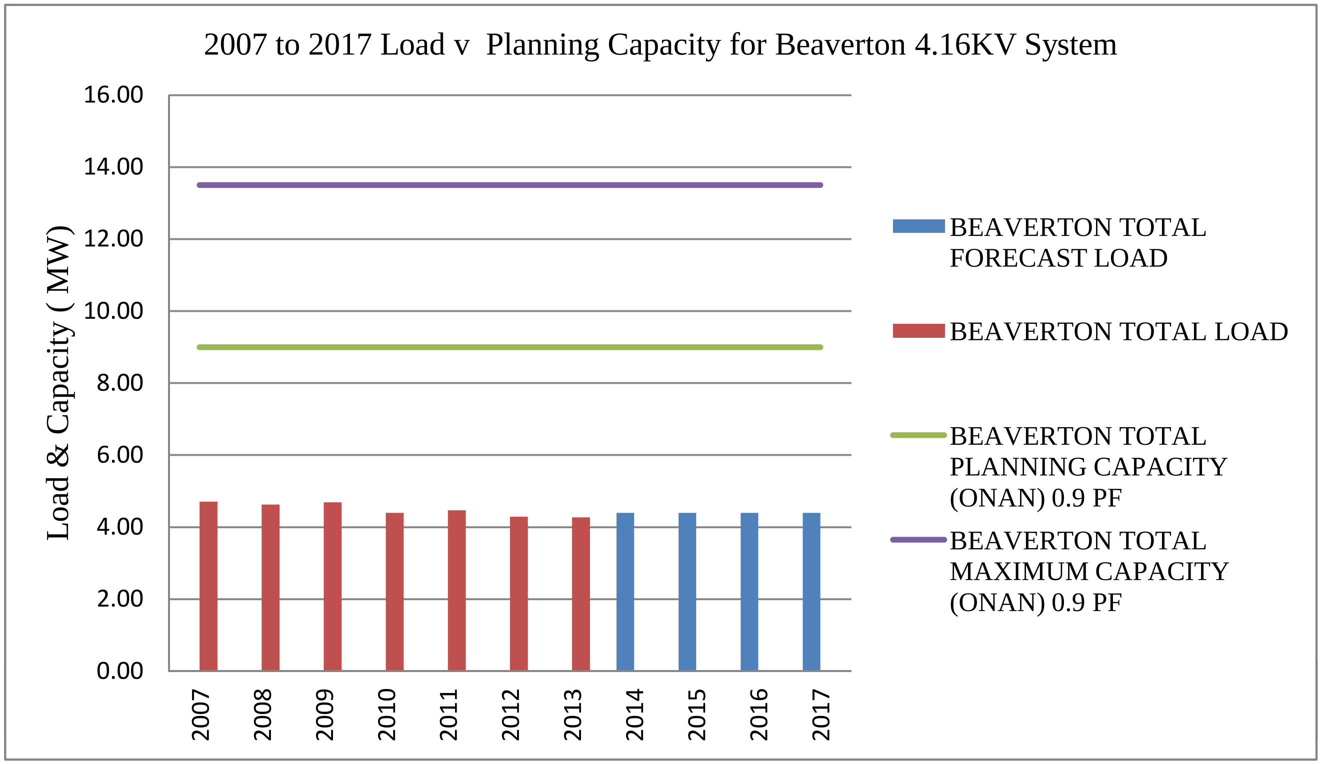
2007 to 2017 Load v Planning Capacity for Newcastle 13.8KV System
Load & Capacity (MW)
30.00
25.00
20.00
15.00
10.00
5.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
NEWCASTLE TOTAL LOAD
NEWCASTLE TOTAL FORECAST LOAD
NEWCASTLE TOTAL PLANNING CAPACITY (ONAN) 0.9 PF
NEWCASTLE TOTAL MAXIMUM CAPACITY (ONAF) 0.9 PF
NEWCASTLE TOTAL MAXIMUM CAPACITY (ONAN) 0.9 PF
NEWCASTLE TOTAL PLANNING CAPACITY (ONAF) 0.9 PF

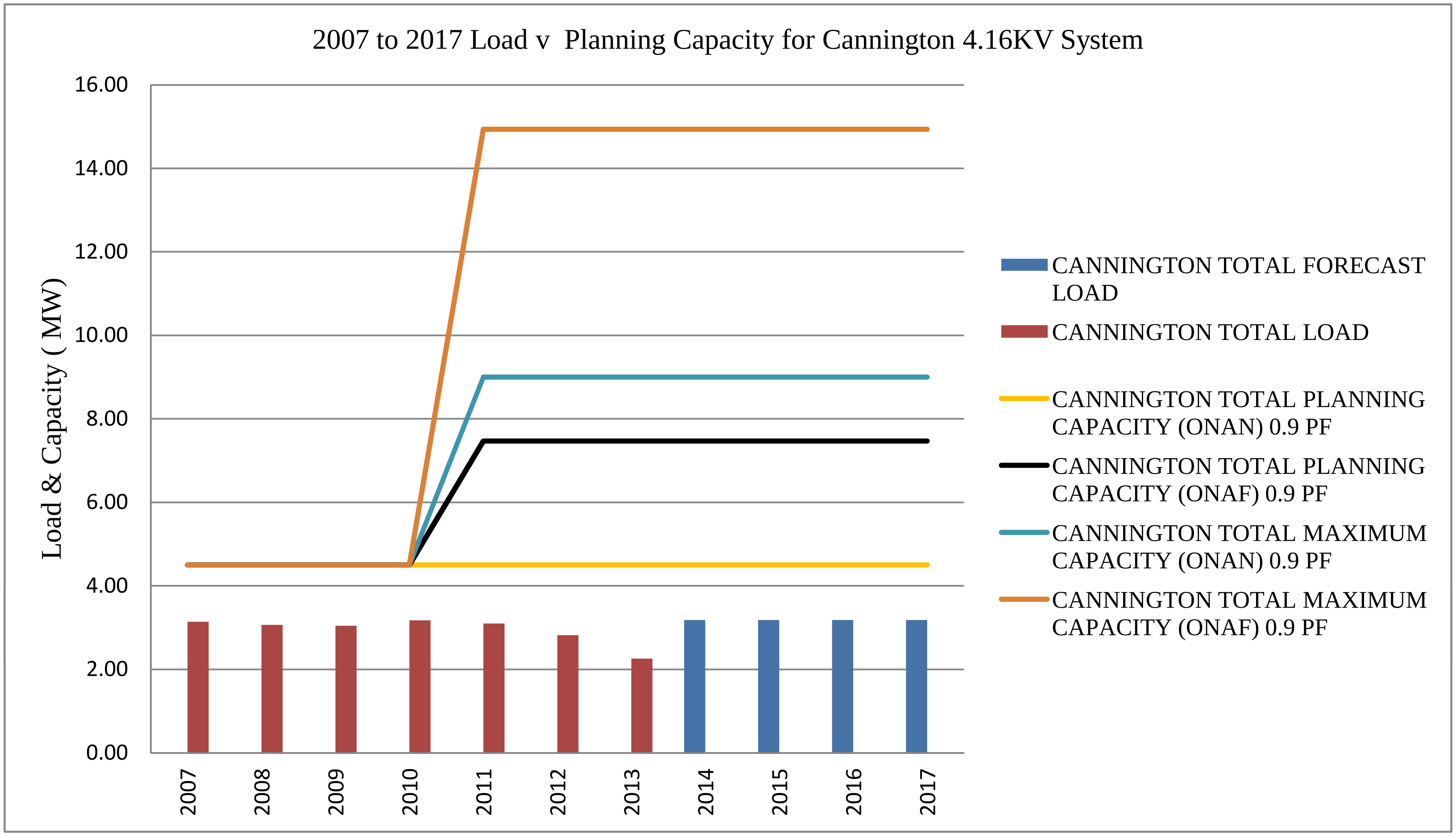

2007 to 2017 Load v Planning Capacity for Port Hope 44KV System
Load & Capacity (MW)
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
PORT HOPE TOTAL LOAD
PORT HOPE TOTAL FORECAST LOAD
PORT HOPE PLANNING CAPACITY (0.9 PF)
PORT HOPE MAXIMUM CAPACITY (0.9 PF)


2007 to 2017 Load v Planning Capacity for Port Hope 27.6KV System
Load & Capacity (MW)
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
PORT HOPE TOTAL LOAD
PORT HOPE TOTAL FORECAST LOAD
PORT HOPE TOTAL PLANNING CAPACITY (ONAN) 0.9 PF
PORT HOPE TOTAL MAXIMUM CAPACITY (ONAN) 0.9 PF

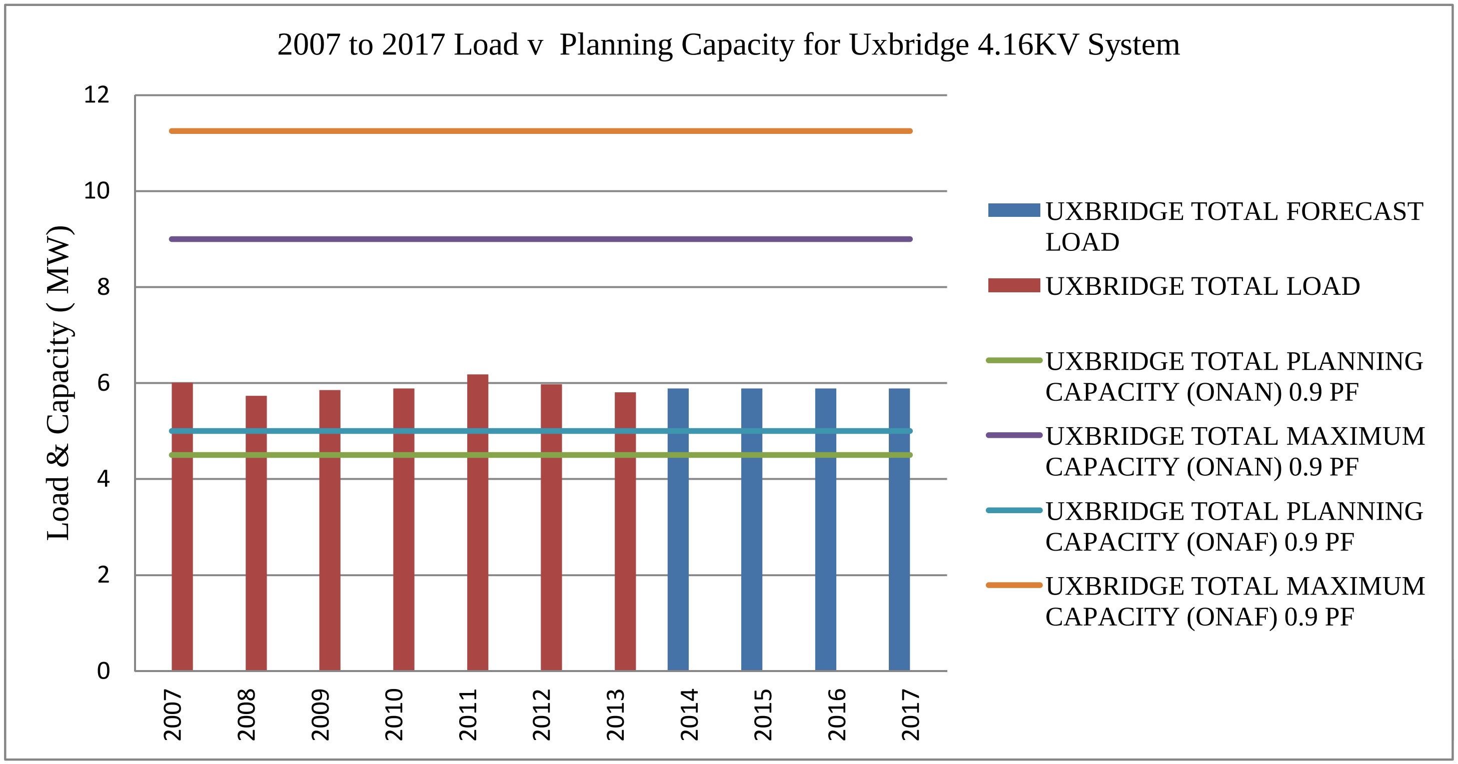

2007 to 2017 Load v Planning Capacity for Port Hope 4.16KV System
Load & Capacity (MW)
25.00
20.00
15.00
10.00
5.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
PORT HOPE TOTAL LOAD
PORT HOPE TOTAL FORECAST LOAD
PORT HOPE TOTAL PLANNING CAPACITY (ONAN) 0.9 PF
PORT HOPE TOTAL MAXIMUM CAPACITY (ONAN) 0.9 PF


2007 to 2017 Load v Planning Capacity for Sunderland 8.32KV System
Load & Capacity (MW)
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
SUNDERLAND TOTAL LOAD
SUNDERLAND FORECAST LOAD
SUNDERLAND MAXIMUM CAPACITY

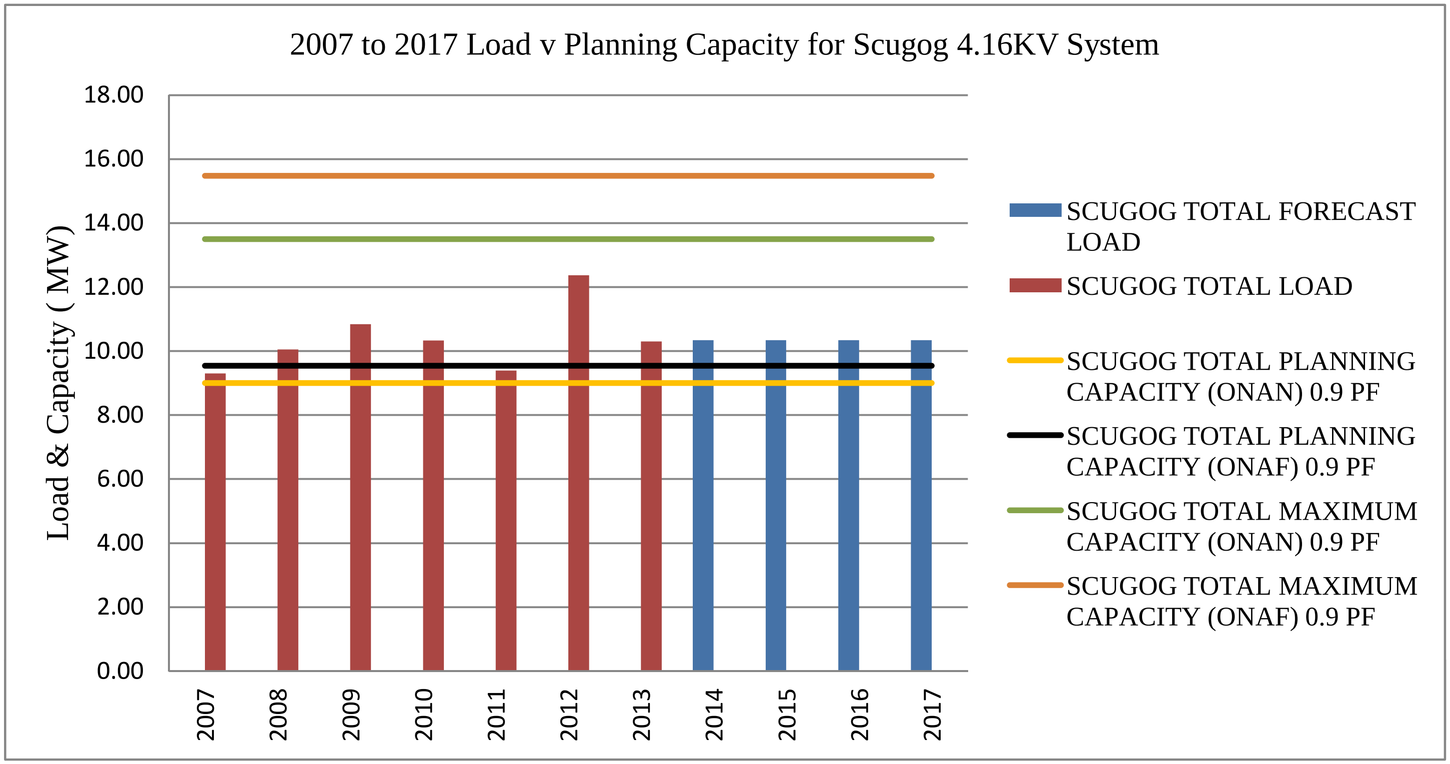

2007 to 2017 Load v Planning Capacity for Beaverton 4.16KV System
Load & Capacity (MW)
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
BEAVERTON TOTAL FORECAST LOAD
BEAVERTON TOTAL LOAD
BEAVERTON TOTAL PLANNING CAPACITY (ONAN) 0.9 PF
BEAVERTON TOTAL MAXIMUM CAPACITY (ONAN) 0.9 PF

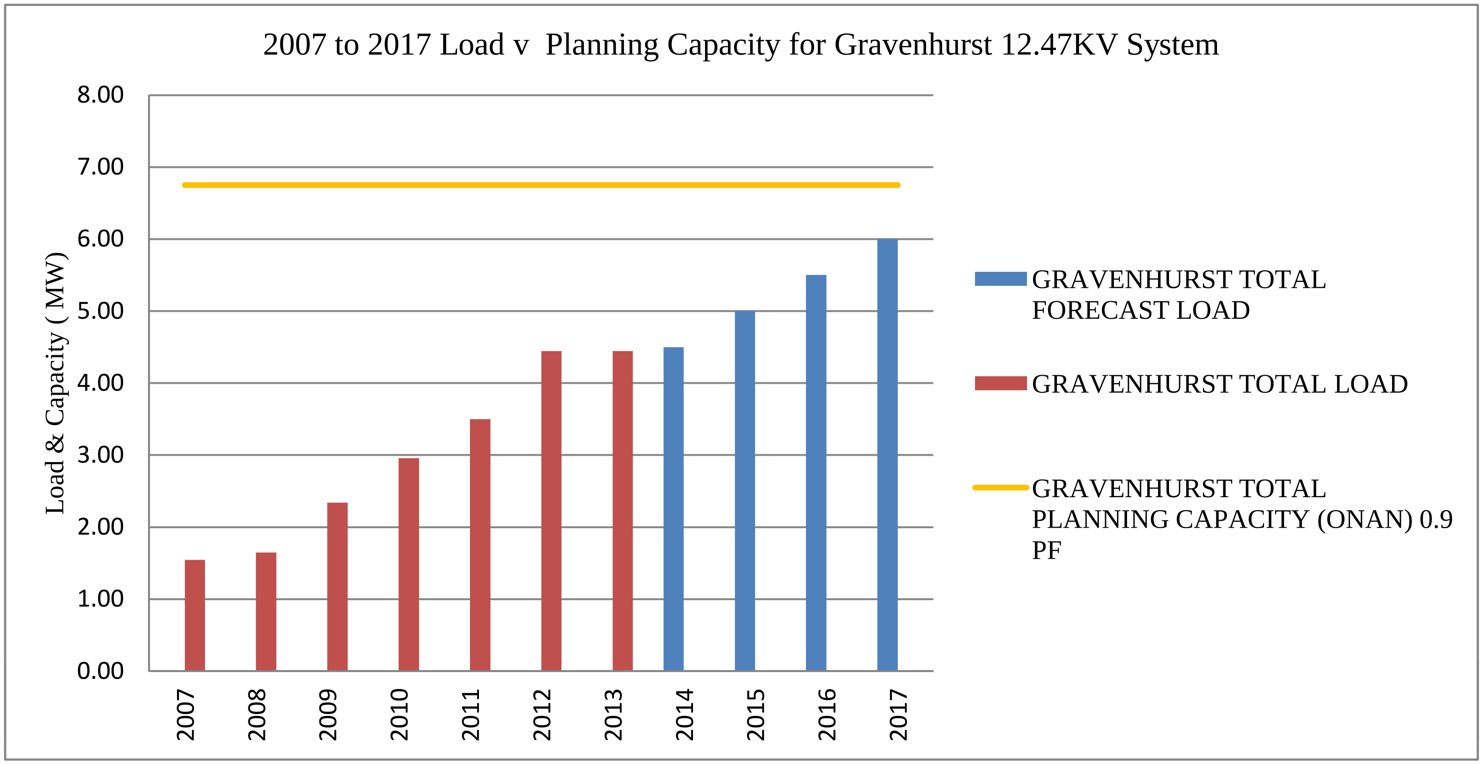


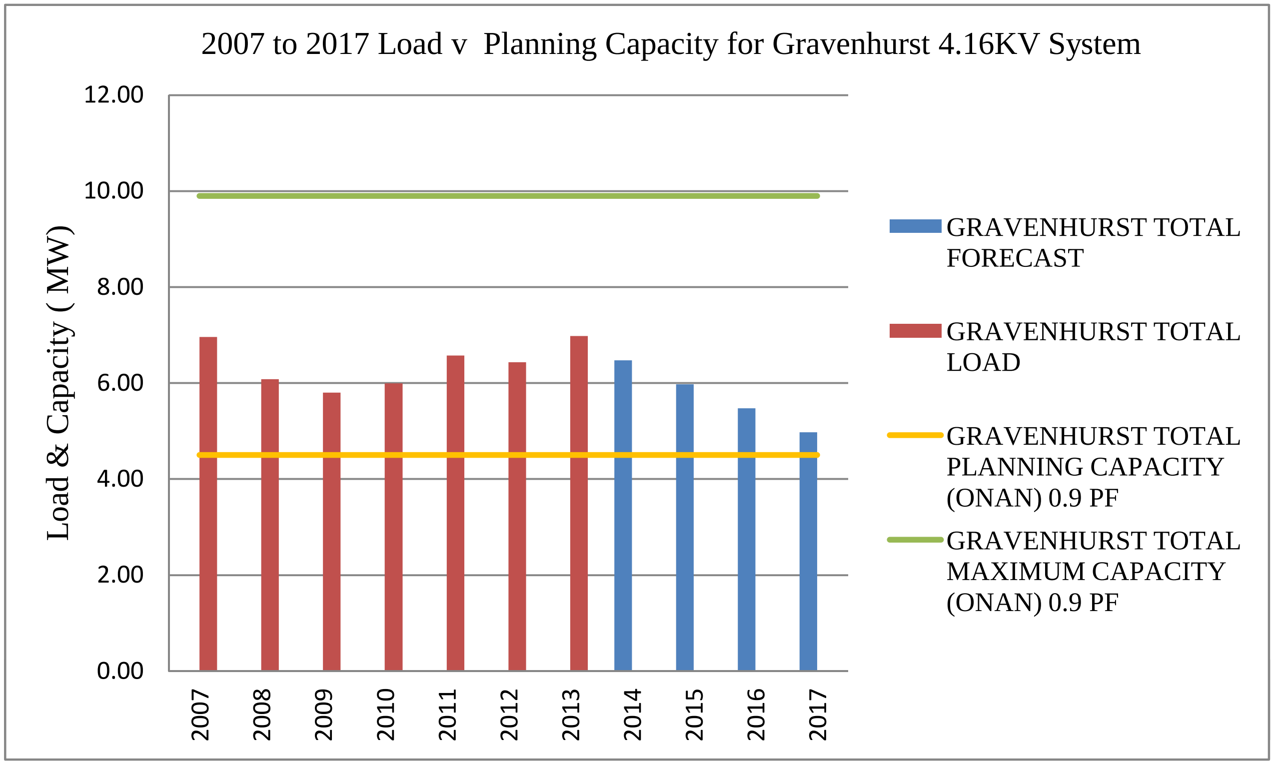
2007 to 2017 Load v Planning Capacity for Cannington 4.16KV System
Load & Capacity (MW)
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
CANNINGTON TOTAL FORECAST LOAD
CANNINGTON TOTAL LOAD
CANNINGTON TOTAL PLANNING CAPACITY (ONAN) 0.9 PF
CANNINGTON TOTAL PLANNING CAPACITY (ONAF) 0.9 PF
CANNINGTON TOTAL MAXIMUM CAPACITY (ONAN) 0.9 PF
CANNINGTON TOTAL MAXIMUM CAPACITY (ONAF) 0.9 PF



2007 to 2017 Load v Planning Capacity for Uxbridge 4.16KV System
Load & Capacity (MW)
0
2
4
6
8
10
12
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
UXBRIDGE TOTAL FORECAST LOAD
UXBRIDGE TOTAL LOAD
UXBRIDGE TOTAL PLANNING CAPACITY (ONAN) 0.9 PF
UXBRIDGE TOTAL MAXIMUM CAPACITY (ONAN) 0.9 PF
UXBRIDGE TOTAL PLANNING CAPACITY (ONAF) 0.9 PF
UXBRIDGE TOTAL MAXIMUM CAPACITY (ONAF) 0.9 PF


2007 to 2017 Load v Planning Capacity for Scugog 4.16KV System
Load & Capacity (MW)
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
SCUGOG TOTAL FORECAST LOAD
SCUGOG TOTAL LOAD
SCUGOG TOTAL PLANNING CAPACITY (ONAN) 0.9 PF
SCUGOG TOTAL PLANNING CAPACITY (ONAF) 0.9 PF
SCUGOG TOTAL MAXIMUM CAPACITY (ONAN) 0.9 PF
SCUGOG TOTAL MAXIMUM CAPACITY (ONAF) 0.9 PF


2007 to 2017 Load v Planning Capacity for Gravenhurst 12.47KV System
Load & Capacity (MW)
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
GRAVENHURST TOTAL FORECAST LOAD
GRAVENHURST TOTAL LOAD
GRAVENHURST TOTAL PLANNING CAPACITY (ONAN) 0.9 PF



2007 to 2017 Load v Planning Capacity for Gravenhurst 4.16KV System
Load & Capacity (MW)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
GRAVENHURST TOTAL FORECAST
GRAVENHURST TOTAL LOAD
GRAVENHURST TOTAL PLANNING CAPACITY (ONAN) 0.9 PF
GRAVENHURST TOTAL MAXIMUM CAPACITY (ONAN) 0.9 PF

Capital Planning Process Overview

This section of the Distribution System Plan (DSP) provides a high level overview of Veridian's capital expenditure planning process.

Key elements of the process that drive the composition of Veridian's proposed capital investments are highlighted and include Veridian's capital planning philosophy, its planning objectives, and their relationship with its asset management objectives.

The planning process is described, including the planning criteria used, and the linkage to the selection and prioritization of Veridian's planned capital investments.

Inputs to the planning process from the Regional Planning Process, customers and REG investments are reviewed.

a) Veridian's Capital Expenditure Planning Objectives

Veridian's capital planning objectives form the high-level philosophy framework for its capital program. These objectives are closely associated with Veridian's asset management objectives and provide guidance to make effective capital investment decisions, which inherently make the best use of, and maximize the value of the assets to the company. The objectives identify an initial starting point and they will continue to be developed, enhanced, or adjusted as necessary to be aligned with the business environment that the company operates in. Similar to the asset management objectives, the capital planning objectives have only recently been formally documented, though Veridian has been operating with their philosophy qualitatively integrated within its planning process to prioritize investments for a number of years including the bridge and test years.

The capital planning objectives are to:

- Ensure capital expenditures are to be made within the approved capital spend envelope for the capital plan and with available resources;
- Harmonize new load with capacity requirements to optimize the timing of capital investments;
- Meet and achieve customer needs and expectations through the superior service and product delivery;
- Complete non-discretionary and discretionary capital investment projects in a cost efficient manner through effective planning and management of resources; and
- Allow flexibility in the plan to accommodate unplanned and unexpected contingencies, with particular attention to improving and increasing reliability.

Planning Process

Veridian's capital planning process has adopted the structure of a rolling five year capital program of which the first two years are the most detailed. For example, the capital program for the years 2013 to 2017 would have 2013 and 2014 as the years with the highest level of detail and certainty. 2015 to 2017 would have capital projects identified, such as sustainment programs for asset replacement, or future road relocations. Some projects, such as the sustainment programs would be already included due to their certainty as being non-discretionary, while the road relocation projects, though non-discretionary in nature, may advance or slide between years based on the third party driver's planning and budget processes and the final versions of their capital programs. Discretionary capital projects also may advance or slide based on new or revised inputs into Veridian's Capital Investment Process (CIP) for prioritization. For example, a neighbourhood area that sees a sudden increase in underground primary cable faults, and was planned in Year 4 of the five year plan, could be advanced to Year 1 or 2 based on how significant the impacts are to customer reliability.

Early in each year, our planning staff request input from the other Veridian business units for their capital projects within their areas of responsibility to update the five year capital program, with particular emphasis on the first two years. These capital projects are considered as candidates only for the capital program. Scopes and costs are generally preliminary and are developed and supported by business cases as the year progresses. In mid-year, the complete list of candidate projects are reviewed collectively and compared to affordability, the strengths of their business cases and CIP scoring. Business cases are required for candidate projects greater than $250,000.

This planning structure allows for business units to have a forward looking road map in planning their investments short term and long term. Finance is able to have the information it requires for financial planning, short term and long term. Capital spending is smoothed year over year to minimize impacts to customers.

The business units involved are:

- Engineering
- Facilities
- Fleet
- Information Service (IT)
- Line Services
- Metering
- Operations

Please refer to Exhibit 2, Tab 3, Schedule 4, for further details on Veridian's CIP.

Capital Investment Drivers for Distribution Plant Assets

Distribution plant assets, as a subtotal within the entire Veridian capital program year over year, are consistently the most significant and highest dollar portion of the capital program.

It is expected that the operational and service requirements driving Veridian's capital expenditures, and found within its DSP, will generally remain consistent through the 2014 to 2018 planning window. The projected expenditures for the test year, and going forward, not only reflect the typical spending needs of a distribution electric utility serving a growing customer base with a geographically distributed, and a diverse collection of physical assets but also include the ongoing planned capital sustainment investments required to replace the aging assets found in its distribution system based on the results of the ACA completed in June 2013. The principal key drivers for capital expenditures for distribution assets are:

- New plant to serve new customers (Growth);
- New or upgraded plant to increase capacity and enhance reliability (Capacity);
- Replacement plant due to damage, failure, or end of useful life (Replacement);
- Relocated/replacement plant to accommodate third-party requirements (Relocation); and
- Performance or technology improvements, some of which are mandated (Performance).

Historically, Veridian has used "Development" and "Sustainment" as its highest internal level of investment categories, with projects being most often grouped by these key drivers; each of which is discussed in detail below. Veridian has mapped the specific projects within its Development and Sustainment categories for the test year only to the four categories as required in the latest Chapter 5 filing requirements.

1) Growth investments include plant upgrades to avoid equipment failure from potential overloads and system expansions to supply new customers in areas that have no distribution service and must be connected to Veridian's distribution system. Depending on the distance from the utility's distribution system, new assets may need to be built in addition to the required service connections. This type of investment is normally classified as Development Capital and considered to be a non-discretionary investment given the utility's obligation to connect new subdivisions and commercial and industrial customers within its service area. This investment category has been a dominant force behind Veridian's capital spending program historically, and is expected for the foreseeable future including the bridge and test years and beyond.

2) Capacity investments are required where there is an increasing load among existing customers, and/or new customers are being added, which eventually causes existing supply assets to reach their technical limits creating reliability and service quality concerns. When this occurs, or is projected to occur, the existing assets must be upgraded, replaced, or supported through other parallel assets. This type of investment is usually classified as Sustainment Capital and can range from optimal to non-discretionary depending on the timing and urgency of the capacity needed and the potential reliability impacts on customers.

3) Replacement investment is required to address damage, failure, or end of useful life of the existing assets. The timing of this investment is assessed in conjunction with the maintenance programs and external factors like storm and third-party damage. When the efficient operating condition of an asset can no longer be sustained through cost effective maintenance or the frequency and impact of failure is undermining customer service, the assets must be replaced. This type of investment is usually classified as Sustainment Capital and can range from optimal for a certain length of time to non-discretionary when eventually immediate replacement is required. The result of Veridian's ACA provides the support for the capital spend

in this investment category for the test year and beyond. Please refer to Exhibit 2, Tab 3, Schedule 6, Attachment 1, for the ACA.

4) Relocation investment is required when distribution assets must be moved and in most cases old plant replaced to accommodate municipal or other third-party requirements. Road authorities have the right to order the relocation of utility plant located on road allowances. Customer requests for plant relocation may also be undertaken. This type of investment is usually classified as Sustainment Capital and non-discretionary when related to mandated road relocations. Road relocation projects are a dominant factor in the determination of Veridian's annual capital spending. There is significant capital spend in this category for both the bridge and test years and beyond based on indications of significant municipal and regional asset replacement and upgrade in roads and subsurface infrastructure. Customer requests for relocation are considered important but optional if there are higher priority distribution projects in the same year, unless there is a safety or reliability issue.

5) Performance investment is required to improve the efficiency and reliability of the system or the existing plant, to provide enhanced operational functionality or to meet new safety, environmental, operational or regulatory requirements. Plant performance that no longer meets current reliability requirements must be updated. Performance investment may also be required if conditions in the surrounding environs have changed to negatively affect asset performance. Expenditures are also required from time to time to meet changing regulatory requirements such as power factor correction upgrades at transformer stations ordered by the Independent Electricity System Operator (IESO). Performance investment is classified as Sustainment Capital and the project priority can range from optimal for a certain requirements to non-discretionary when improvement or technology change is mandated by legislation or regulators.

A secondary driver of investments in distribution assets are opportunities for leveraged investment. Veridian routinely takes advantage of opportunities to upgrade (or harden) its distribution plant to become more weather resistant. Opportunities for enhancement include road relocation projects, capacity upgrades, and plant replacements or upgrades due to new connections. Hardening the infrastructure will in most cases be an indirect result of building new or replacement installations to more modern standards (stronger class poles, more or improved guying, increased clearances, animal protection, and more environment resistant hardware and insulation). In addition, where feeder or line sections have exhibited higher than expected failure rates, new construction designs for other purposes will consider features to mitigate against the potential for excess failures (additional storm guying, wider separation from vegetation, and in some cases the use of underground cables where unavoidable tree clearances indicate a continued high risk due to storms). No design or construction project is done to meet a single purpose and as many as possible prudent and financially reasonable upgrades are included to meet the future requirements based on the best information available at the time. For example, for overhead, taller poles are installed to accommodate future circuits, and additional ducts are installed under roads for future underground circuits.

Other capital investment, such as fleet, facilities, information technologies and miscellaneous consists mostly of physical resources and equipment required to allow the business and staff to function. This is often considered discretionary spending because there is usually some degree of flexibility in the required timing of the expenditure. The processes and key drivers for this spending type are discussed in Exhibit 2, Tab 3, Schedule 6 – Asset Lifecycle Optimization Policies and Practices for IT, Fleet and Facilities.

Capital Investment Planning Criteria

Veridian plans for and sets its capital spending envelope each year by balancing its bottom up identification of capital project needs with its top down consideration of its capital planning objectives. Capital spending is driven by capital needs identification. Projects are identified as potential candidates for the budget, and the total capital expenditures planned for the year are assessed with regard to previous spending levels, rate impacts, customer service value, shareholder investment and the need to proceed with non-discretionary projects. In the past, the total capital expenditure in any one year was primarily driven by the amount of non-discretionary requirements which had been identified through engagement with the municipalities or their consultants. In the years where the amount of non-discretionary investment exceeded the normal capital spending level, the non-discretionary projects would be approved out of necessity and all of the discretionary projects would be deferred. It became quite evident that the repeated deferral of discretionary projects led, and would continue to lead, to a backlog which was neither sustainable nor desirable. To address this problem, starting in 2012 Veridian increased its capital spending envelope to allow its investment in resources and capital each year to be at a higher level to allow broader planning flexibility. Veridian plans to maintain this steady state investment in non-discretionary and discretionary assets through and past the bridge and test years.

Planning Criteria Source Data

Veridian uses several sources of information and data to assess the status of its distribution system assets and to assist in planning and determining the capital and operational investments to be made in the system. These sources of information and data are:

- Geographic Information System (GIS);
- Capital Investment Process (CIP), (Exhibit 2, Tab 3, Schedule 4);
- Asset Condition Assessment (ACA), (Exhibit 2, Tab 3, Schedule 6, Attachment 1);

- System Loading, Load Trends and New Customers forecasts;
- Reliability information; (Exhibit 2, Tab 4, Schedule 2);
- Inspection and Maintenance programs, (Exhibit 2, Tab 3, Schedule 6); and
- Customer Satisfaction, (Exhibit 2, Tab 3, Schedule 7).

Some of the sources have been detailed in other sections of the rate application as noted. Veridian continues to upgrade its existing information resources to allow staff to maintain a complete operational understanding of all present and pending system growth needs and capacity, or other risks.

Geographic Information System (GIS): Veridian's GIS is the database for its distribution asset register and serves to be an accurate model of Veridian's physical electrical distribution system. The GIS support planning and maintenance activities by providing and maintaining the source data used to drive the inspections program, as well as collecting data from field crews and updating data sources accordingly. In the past much of this work involved manual data entry. Through continued development of Veridian's mobile computing initiative, these processes will become more efficient and will allow the collection and recording of additional data as required without requirement for additional labour resources.

System Loading: Information is collected automatically (some manually) on system peak loading at many points in the system, using IESO meters, Veridian supply point meters, and substation feeder and sub-feeder load measurement devices. This data is analyzed as needed in various software applications to measure the risk of system overloading and mitigate any concerns. Load forecasting and capital growth planning are and will continue to be the underlying basis for the near and longer-term capital requirements for new or enhanced capacity. Veridian's efforts in forecasting these demand based investments are made more challenging due to the numerous distinct and disparate operating districts that Veridian services, that have varying features between them such as differing economic conditions and physical geography. Please refer to Exhibit 2, Tab 3, Schedule 5, for additional details. Veridian makes best efforts to apply its capital investment strategy consistently and equitably across all of the areas that it serves.

Load Trends and Supply Point Changes: Historic and expected load growth is tracked and charted and regularly reviewed and integrated with the transmitter's (Hydro One) TS plans and requirements for upstream system changes, operating constraints and new facility development. The effects of Conservation and Demand Management (CDM) and Distributed Generation (DG) effects are currently considered in loading/capacity planning and integrated into our load forecasting model.

New Customers: Growth is predicted and planned for using a combination of growth projections, historic growth patterns and load forecast models. Information is exchanged with external sources such as municipal economic development offices; residential, commercial and industrial land developers; and municipal community planners to improve the timeliness and accuracy of system growth data.

Inspection and Maintenance Programs, Equipment Failure Analysis: Veridian maintains a full schedule of plant inspections operating on a three-to-six year rotation as required by the Distribution System Code. Ongoing inspection activity identifies varying amounts of capital work requirements annually for each type of asset as a result of equipment being identified as defective, non-repairable or near the end of its efficient operating life. Similarly, when there has been an equipment failure, root cause analysis may indicate a systemic problem requiring targeted plant replacements to avoid further unexpected losses.

Customer Satisfaction: Veridian conducts customer surveys and retains complaint resolution and call centre records as a measure of its service quality. These records are used in combination with its reliability measures (ESQRs) to identify problem areas requiring non-scheduled inspection and assessment to determine if existing plant should be replaced or repaired.

<u>System Planning Criteria</u>

Veridian's planning criteria are separated between Transformer Stations and Municipal Substations.

For Transformer Stations (TSs)

The details for each of the TSs that supply Veridian are provided in Exhibit 1, Tab 4, Schedule 9, Attachment 1. Veridian uses the single contingency planning criteria for each of these TSs to define Veridian's portion of the TSs capacity limit. For example, Hydro One owned Cherrywood TS, supplies Veridian exclusively with eight (8) 44kV feeders. The feeder ratings are based on Cherrywood TSs Limited Time Rating (LTR). Typically, the capacity of a TS is determined by the "Limited Time Rating" (LTR) of one of the two transformers. This is based on the assumption that one transformer could be forced out of service at any time leaving the remaining transformer to carry all of the load. For example, a typical transformer with a 75MVA rating can be used to carry 125MVA continuously if cooling fans and oil circulating pumps are used and 167MVA for up to ten days in an emergency. Cherrywood TS's 10 day LTR is 193MVA. When the power factor of 0.9 is applied, the 10 day LTR is 176MW, or 176MW/8 feeders = 22MW per 44kV feeder. Veridian's system planning staff removed one (1) of these 44kV feeders from their calculations and studies which defines a lower planning capacity limit for the TS transformers. Veridian has chosen to use this conservative approach with the TS transformers operating at a lower planning capacity level rather than operating the TS transformers at full capacity. There is risk with the latter approach as it does not allow for any buffer both in capacity nor time to determine alternative supply arrangements. For example and continuing from the above, 8 feeders operating at 22MW = 176MW. 176MW would be the 10 day LTR planning criteria of the TS transformers. There is no buffer in this case. The planning capacity is equal to the transformer capacity. Veridian's approach as described above would be 7 feeders operating at 22MW = 154MW. 154MW, once reached through actual load, would be the planning criteria that would flag necessary actions. A higher rise in actual unforecasted load may also initiate an earlier flag for action, especially if the unforecasted load appears that it will continue over time. The alternatives would vary between short term and long term in timelines and range from do nothing, as there is 20MW of capacity still available (short term), switching some load to a different TS if possible (short term), or initiate the process to meet with the transmitter for an expansion or upgrade of the TS in some manner (long term).

Other TSs are shared between Veridian and other distributers. Even though Veridian uses the single contingency planning criteria for its portion of the TSs, there is no mechanism at the present time that allows information on the entire actual load for the TS to be shared amongst the user distributors to determine the total actual load on the TS for planning purposes. The transmitter maintains this information and it is currently not shared. Veridian has requested this sharing of information, with the other distributors' permission, in order to better evaluate the load on the TS transformers. At this time, there is reliance on the transmitter to identify a capacity issue on behalf of the distributors rather than the distributors knowing and operating within their own planning capacity levels. This is seen as a risk that could be mitigated through sharing of information amongst all parties involved. For example, where two distributers share a TS, one distributor may be operating in a conservative manner at its planning capacity, while the other distributer exceeding its allowed capacity and operating beyond its planning capacity. The possible result could be the capacity that the first distributor may be relying on, based on its planning criteria, that should be available for new customers is not actually available when needed.

For Municipal Substations (MSs)

Similarly as with the TSs, Veridian uses the single contingency planning criteria for its Municipal Substations. Veridian has defined 16 areas within its service area. Once the area is defined, the MS transformer capacity in that area is totalled and then one (1) of the largest MS transformer within that area is removed from service which removes that available capacity. For example, Area X has four (4) MS transformers with 100MVA Oil Natural Air Natural (ONAN) and 120 MVA Oil Natural Air Forced (ONAF) capacity. Veridian's system planning staff remove one of the four MS transformers (15MVA ONAN and 25MVA ONAF) from their calculations and studies which now defines a lower planning capacity limit for the area at 85MVA ONAN and 95MVA ONAF. Veridian has chosen to use this conservative approach with the MS transformers operating at a lower planning capacity level rather than operating the MS transformers at full capacity. There is risk with the latter approach as it does not allow for any buffer both in capacity nor time to determine alternative supply arrangements.

Veridian looks to maintain its area actual load profile between the ONAN and ONAF (if installed) MVA ratings of the MS transformer as its operating limits. Veridian deems this a reasonable operating philosophy in that the use of the asset is maximized but that it still operates below its equipment ratings. Similarly as with the TSs, there is enough capacity and time buffer introduced to flag necessary actions early enough to deliver just in time alternatives.

It should be noted that planning capacity charts already include the removal of one feeder or one transformer as applicable and as described above.

<u>Relationships with Asset Management Objectives</u>

As noted above, the capital expenditure planning objectives are closely associated and aligned with the asset management objectives for the development and planning of capital investments, and practically cannot be discretely separated, as the combined objectives represent Veridian's overall philosophy.

Municipal Substations (MSs)

Veridian's municipal substations wholly, have been identified as being the single most critical asset within its distribution system. Due to its non-contiguous service area, Veridian is required to operate a higher number of substations than most distributors, which in turn means a higher number of substation assets to be maintained, repaired, replaced or refurbished. This identified criticality and the numbers involved, has driven the requirement for increased capital investment in this asset category and the necessity for dedicated resources to address the ACA results.

New MSs

New MSs are designed and constructed to the latest Veridian standards. The components of Veridian's CIP are qualitatively incorporated into the design. The design and construction of the substations follow good utility practice, standardization to ensure consistent results, and a preference for plug in off the shelf components rather than customized or exclusive components. For example, the environmental component of the CIP is translated into the SorbWeb Plus installation. SorbWeb Plus is a gravity-based subterranean secondary oil spill containment system that surrounds oil-filled equipment with geosynthetic materials. The system effectively traps oil from catastrophic oil spills and leaks. The safety component of the CIP is translated into using dead-front equipment for the substation equipment.

Existing MSs

Substation assets, as well as any piece of equipment associated with a substation related to capacity are generally considered in the same manner as the other asset categories. The philosophy under the secondary driver section which has been described above applies here as well. For example, wood pole replacements are not necessarily replaced on a like-for-like basis but there is consideration for future needs, increased clearances and replacement based on current design standards. Similarly, substations are not typically replaced on a like-for-like basis, but there is always consideration whether to increase capacity, upgrade equipment, eliminate non-standard or obsolete components and utilize current installation methods for consistency, long term reliability and improved system performance.

Accommodating Connection of Renewable Generation Facilities

Please refer to Exhibit 2, Tab 6, Schedule 3.

b) Non-Distribution System Alternatives to Capacity or Operation Constraints

Veridian's CDM initiatives have been incorporated into Veridian system loading analysis meaning that the expected targets have reduced the capacity requirements. Veridian currently promotes all Ontario Power Authority province-wide CDM programs to customers throughout its service area. All CDM potential is pursued, which naturally relieves capacity constraints where they exist.

The Regional Planning Process is at a very preliminary stage. Please refer to Exhibit 2, Tab 3, Schedule 5, for additional details.

c) Capital Investment Process

Please refer to Veridian's Capital Investment Process (CIP) at Exhibit 2, Tab 3, Schedule 4.

d) Description of Customer Engagement related to Capital Expenditure Planning

Veridian employs a variety of communications channels to solicit customer and stakeholder feedback on its business operations. Valuable information on customer/stakeholder preferences, issues and business plans is secured through these channels, and this information informs the development of Veridian's own business initiatives. Please refer to Exhibit 1, Tab 2, Schedule 1 for further details.

Customer complaints are addressed as per Veridian policy AD34 Customer Complaint and Dispute Resolution Policy at Exhibit 2, Tab 3, Schedule 8, Attachment 5.

Customer feedback may be incorporated at any time in the capital project process from initial planning through design up to construction. For example, customer complaints about reliability would go as input into the planning process to review existing overhead clearances and may impact design. Complaints about how driveway aprons were replaced during an underground cable replacement would be input into the planning process and be incorporated into the Request for Quotation (RFQ) to issue to approved bidders for the next phase of underground cable replacement project to either eliminate or mitigate the issues. Veridian Inspectors would also be made aware to play close attention to the specific issues during the construction period.

e) Prioritization of REG Investments

The prioritization process for REG expansions is the same as for distribution system expansion projects where the REG expansion is triggered and driven by customer requirements.

Veridian is actively participating in the ownership and operation of REG projects supported through the Feed in Tariff (FIT) program operated by the OPA. Veridian currently owns and operates a 120kW AC system on the roof of its Ajax head-office location. Veridian has recently received a FIT Contract Offer for a second project to be located on the Claremont Community Centre roof in Pickering. This second project will be approximately 100kW AC in size and will be completed during 2014. Veridian is contemplating further FIT applications for projects within its various service territories through the 2014 Test Year. Veridian does not contemplate any impact with regards to its projects on the prioritization of distribution system expansions to accommodate REG connections. As previously stated, Veridian's distribution system currently has capacity to connect REG projects through the 2014 Test Year, without the necessity of expanding its distribution system, with the exception of the non-utility owned Index Energy project, which has been described previously in Exhibit 2, Tab 3, Schedule 9.

Attachment 1 of 5

Estimated and Actual Cost Differences

Estimated and Actual Cost Differences

Overview

Material differences can exist between preliminary estimated project costs and final realized (actual) project costs. The overall difference in any instance can be broken down into variances between preliminary engineering and final engineering cost estimates, and variances between final engineering estimates and actual costs. For purposes of its regulatory applications, it is often necessary for Veridian to use preliminary engineering estimates because they represent the only available information at the time the applications are prepared. Veridian's planning, engineering, and construction processes necessarily take place on a continuous basis rather than on a discrete calendar year basis, in order to meet customer demands and internal requirements. Project instigation by customer demands (e.g., subdivision developments, requests for equipment re-locations) occurs continuously throughout the year. In addition, internally identified requirements also appear continuously throughout the year, over and above planned work that originates from an annual planning cycle.

Project lifecycles vary between different categories of projects, both in terms of total time required from start to finish and in terms of the discrete steps involved. However, it is typical for projects to have a lifecycle that includes the following major stages:

1. Need identification (internally or externally generated)
2. Initial assessment and preliminary engineering estimate
3. Detailed project design and engineering estimate

4. Construction
5. Completion and closure

Because of the continuous process of needs identification, design, and construction, a ‘snapshot’ of projects taken at any point in time will reveal projects at various stages of the entire lifecycle. Such snapshots are necessary both for internal planning and budgeting purposes and for purposes of preparing rate applications.

Differences between Preliminary and Final Engineering Estimates

It is commonplace in the lifecycle of projects for initial estimates of costs to be prepared, in order to meet requirements of (prospective) customers, or internal planning needs for a budget to be finalized by a given date. However, at the early stages of a project it is also commonplace for there to be only preliminary information available to Veridian on which to base its cost estimates.

When a preliminary cost estimate is needed, Veridian uses techniques appropriate to the nature of the project to estimate cost in the absence of detailed information on specific requirements. For example, in the case of a subdivision project supplied by underground equipment, Veridian may need to make preliminary assumptions about lot density, average load per residence, and other factors in order to produce a preliminary estimate. The preliminary estimate in this example would then be based on those assumptions. When it is necessary to provide estimated cost information, either to a customer or for purposes of a budget or rate application, it may be that the preliminary estimate is the only information available given the stage of progress for the project.

As a project matures through the design phase, additional specific information about relevant parameters becomes available and detailed designs for the electrical and other (e.g., civil) components of a project can eventually be completed.

Variances between the preliminary and final engineering estimates of project costs can arise due to differences between the initially assumed parameters of a project and the final design parameters, and also due to changes in scope of the project (the addition or subtraction of discrete project elements). These variances can be in either direction, although there is a tendency for costs to grow as project details and design become resolved at greater levels of detail, since additional requirements may become apparent.

Difference Between Final Engineering Estimates and Actual Costs

While the final engineering design (and corresponding estimate) is an accurate reflection of the intended execution of a project, unforeseeable external factors including field conditions can come into play to cause variances between the expected costs of the final design and the actual costs. There are many factors which can contribute to such variances; some examples include:

- Delays in the start or completion of construction due to external factors such as acquiring permits; coordinating with other infrastructure providers or municipalities; changes in customer circumstances or readiness; and emergence of higher priority projects which divert resources from the project in question
- Changes in actual prices of material
- Changes in availability of materials causing a change in design

- Unforeseen field conditions (e.g., soil conditions, presence of physical obstacles, presence of previously unknown deterioration in supporting or connecting equipment requiring remediation, adverse weather)

Given the sometimes long life cycles of projects, all of these factors can combine to produce variances between initial engineering cost estimates and final actual costs.

VERIDIAN
CONNECTIONS

File Number:EB-2013-0174

Exhibit: 2
Tab: 3
Schedule: 8

Date Filed:October 31, 2013

Attachment 2 of 5

Explanation of Contribution Policy

Explanation of Contribution Policy

As the licenced distributor for its service area, Veridian is obliged to connect customers requesting service (with certain conditions applying) and to relocate or remove its existing equipment when requested to do so by a competent and recognized authority. In both of these situations, Veridian may receive payments outside of regulated distribution rate revenues in connection with these activities, pursuant to applicable statutes, regulations, and codes. This evidence briefly describes Veridian's policy and practice with respect to these matters.

Capital Contributions for the Connection of Customers

In many cases the connection of new customers, for example in residential subdivisions or other new developments, requires expansion of Veridian's system. In most instances of new project development, the project proponent may be a developer or other party that will not be the ultimate end-use electricity customer; in other cases the project proponent is the end-use customer. In both cases, it is Veridian's policy, pursuant to the Distribution System Code ("DSC") and Veridian's Conditions of Service, to conduct an Economic Evaluation of the proposed project according to the protocols set out in the DSC and relevant appendices to that Code. In cases where the Economic Evaluation indicates that there would be a shortfall of the present value of revenues compared to costs for completing the project, it is Veridian's policy, as authorized by the DSC, to collect a capital contribution to offset its capital cost of the project, as well as other forms of security. The DSC and Veridian's Conditions of Service set out in detail the conditions under which a capital contribution is payable, as well as the methodology of the Economic Evaluation.

For purposes of budgeting and capital planning in the case of subdivisions, it is Veridian's practice to use an estimate of the costs per lot to bring service to the area. The current estimate is based on historical information and trends in costs between 2007 and 2011, as well as experience concerning the proportion of costs covered through capital contributions. On average over this period, Veridian paid 53% of the total cost and developers paid 47% through capital contributions.

However, due to changes in the DSC to take effect in 2014, Veridian will exclude from the calculation of the capital contribution the cost element related to upstream system enhancements, which had been charged on a per kW basis historically to offset system enhancement costs which could not be attributed directly to single projects. Pursuant to the current DSC, Veridian will in 2014 and onward absorb those costs into rate base. This change has the effect of reducing the developer contribution, and after analysing data from 2009 to 2011, Veridian estimates that this will result in Veridian bearing responsibility for approximately 65% of subdivision project costs, and developers bearing responsibility for approximately 35% of the costs. It is Veridian's practice to update these estimates as new information becomes available and review of historic actuals.

For commercial and industrial developments, Veridian conducts a similar Economic Evaluation as for residential projects should a system expansion be required.

Road Authority Projects

Almost all of Veridian's distribution plant is located within road allowances. Provincial, Regional, and Municipal road authorities may, at their discretion, initiate projects to construct, re-construct, change, alter, improve or relocate its roads as necessary based on their planning needs. Other related projects that may be typically associated with any road works are, but not limited to, the installation of sidewalks, water supply, sanitary and storm sewer infrastructure type renewals or replacements. Road authorities when necessary may require that Veridian relocate and/or rebuild its distribution system assets to accommodate such projects.

Planning for these projects takes place over several years and plans for particular projects become more firm as time progresses. Veridian annually reviews its five-year road authority projects to determine where work might or will be required, and as plans become confirmed, incorporates that information into its near term capital expenditure plan.

The *Public Services Works on Highways Act* ("PSWHA") makes provision for Veridian and the road authority to agree and share on the apportionment of costs. In lieu of such an agreement, the default arrangement in the PSWHA is that the cost of labour, as defined within the PSWHA, is shared equally, with all other costs borne by Veridian. Otherwise, alternate cost sharing arrangements as described below may be agreed upon depending on the nature of the project being undertaken.

<u>Like-for-Like Relocation (PSWHA default arrangement).</u>

A like-for-like relocation refers to the replacement of the components or assemblies of an existing distribution system installation such that the new distribution system installation maintains the characteristics and functionality of the original installation. For example, a like-for-like replacement occurs when an existing pole line is replaced with a new pole line having the same number of circuits on poles of the same description.

In this case, the cost sharing arrangement is that the costs for labour, as defined within the PSWHA, are shared on an equal basis, and Veridian is responsible to bear 100% of the cost of the material. Table 1 shows the cost sharing arrangement.

Table 1 – Cost Sharing Arrangement for Like-for-Like Relocations

	Labour Costs	Vehicles Costs	Contractor Costs	Material Costs
Road Authority	50%	50%	50%	0%
Veridian	50%	50%	50%	100%

Non Like-for-Like Relocation

A non like-for-like relocation occurs when there is a change to the existing distribution system installation such that the new installation does not maintain the characteristics and functionality of the original installation. For example, a relocation would not be considered like-for-like when an existing pole line is replaced with a new pole line, with the same number of circuits but with taller poles that are needed to satisfy increased height requirements for new municipality owned street lighting.

With such relocations, cost sharing is determined as with like-for-like projects, with the additional inclusion that the road authority or Veridian covers 100% of the incremental costs based on which party is the driver for the change. In the example above, this would capture the incremental cost of the taller poles relative to the cost of replacement poles of the same length because the road authority in this case was the driver for requiring the taller poles. If Veridian required the taller poles for the addition of another circuit, then Veridian would be responsible to bear the incremental cost of the taller poles, and it would be deemed as a distribution system enhancement. Table 2 shows the cost sharing arrangement

Table 2 – Cost Sharing Arrangement for Non Like-for-Like Relocations

	Like-for-Like Portion				Non Like-for-Like Portion	
	Labour	**Vehicles**	**Contractor**	**Material**	**Change driven by Road Authority**	**Change driven by Veridian**
Road Authority	50%	50%	50%	0%	100% on all cost elements	0%
Veridian	50%	50%	50%	100%	0%	100% on all cost elements

<u>Alternate Construction Relocation</u>

An alternate construction relocation is a variation of a non-like-for-like relocation in which the existing distribution system installation must be removed, altered, or reconstructed to accommodate a road authority project, but which cannot be replaced with the similar type of construction because of new project related technical constraints that did not exist previously with the original distribution system installation. For example, a highway widening may require that the spans between the existing overhead wood pole line be increased to a point beyond which wood poles could be used for the relocation due to the increased physical loading on the wood poles. In this case the new distribution system installation must be substantially different and as such the wood poles must be replaced with engineered steel poles or underground primary cable installed in ducts.

In these cases, the original installation whether overhead or underground is the basis against which the new installation is compared against.

In the case of the example above of an existing overhead wood pole line that is being replaced by an underground installation, the road authority and Veridian would share costs as with the like-for-like relocation but the road authority would bear the responsibility for 100% of the incremental cost of the new underground duct and cable structure relative to the original installation. Veridian would contribute its share of the (hypothetical) current cost of the like-for-like original wood pole structure carrying the same circuits over the same feeder segment length in question.

Relocation for Aesthetics Only

In the case where Veridian is requested to relocate, alter or change its existing distribution system installation for aesthetic, or non-technical reasons only, the road authority will bear the responsibility for 100% of the costs of this type of relocation.

Removal of Plant

In the case where the distribution system installation is simply removed, as may occur for example in the case of expropriation of lands previously serviced, the cost sharing arrangement is the same as for like-for-like relocations.

Temporary Relocation

Temporary relocation of a distribution system installation is sometimes required to permit construction of certain elements of a road works project, such as bridges. In these cases, the existing installation is removed, a temporary installation is completed and then removed upon the completion of the project activity, and then the existing installation is restored. The road authority bears the responsibility for 100% of the costs of this type of relocation.

Attachment 3 of 5

Equipment and Construction Standards

Equipment and Construction Standards

As a licenced distributor, Veridian is obliged to construct and maintain its electricity distribution system in a manner that ensures adequate, reliable, and safe service to customers. To facilitate this, Veridian maintains, and where necessary develops, standards of design and construction that govern the selection, design and installation of electricity distribution equipment on its system. These standards meet, and in many cases exceed, minimum requirements set out by governmental authorities, and reflect good utility practice in areas where standards are not set by those authorities. All of Veridian's design and construction practices, along with its equipment standards, comply with Ontario Regulation 22/04.

This evidence briefly describes the major categories of Veridian's electricity distribution equipment and outlines the major standards applicable to that equipment.

Overhead Feeder Design and Equipment Selection

Major elements of Veridian's overhead distribution system include poles, conductors, switches and transformers.

Veridian standards for overhead equipment either meet or exceed Canadian Standard Association's "*CSA C22.3 No 1-7 Overhead Systems*" standards, where those standards exist. Other internationally recognized standards are used to supplement CSA where the CSA does not offer guidance. These include standards and guidance published by the:

- American National Standard Institute (ANSI);
- American Society for Testing and Materials (ASTM International);
- Canadian Electrical Association (CEA);
- Electrical Safety Authority (ESA);
- Institute of Electrical and Electronic Engineers (IEEE);
- International Electrotechnical Commission (IEC);
- National Electrical Manufacturers Association (NEMA);
- National Energy Board (NEB);
- National Research Council (NRC); and
- Underwriters Laboratories (UL).

Poles are used to suspend conductors and other pole-mounted equipment at safe clearances above the ground, and maintain safe clearances between electrically live equipment, as well as other objects. Poles must be capable of withstanding considerable mechanical loads from the suspended equipment as well as other factors such as wind and ice. The loads exerted on poles are complex and require sophisticated analysis in order to ensure safe and reliable design.

Poles are made of wood, reinforced concrete, or steel, and are classified according to load bearing capability, with wood pole classes up to H3 being the strongest. Poles are anchored in or to the ground in a variety of ways and are often reinforced with guy wires installed to limit the travel or bend of the poles under load and to counter the unbalanced tension produced by conductors from line angles and dead-ends.

Veridian typically uses class 2 poles to suspend primary feeders, with pole lengths ranging from 50 to 75 feet depending on the span between poles and the topography of installation. Shorter and lower class poles are used to carry single phase secondary lines.

Conductors, transformers, and switches are sized according to the loads they must serve. Conductors now in common use are made from aluminum; copper conductors are no longer in common use due to cost and weight.. Larger conductors are made from strands of the conductor material and are designated as aluminum stranded conductor (ASC) and may be reinforced with steel for tensile strength designated as aluminum conductor steel reinforced (ACSR). Conductors carrying higher currents must be larger to avoid overheating and sagging, which if it occurs can cause the stretched conductors to violate clearance requirements and lead to complete failure.

For smaller gauge conductors, conductor size is stated according to standard American Wire Gauge terminology, with the largest diameter in this group being 0000 or 4/0 ("four aught")., Larger wire gauges are nominated in terms of circular mils, a unit of area equal to the cross sectional area of a circle with a diameter of one mil, or thousandth of an inch. One million circular mils is the area of a circle with a diameter of 1 inch. A cable of this cross sectional area would be denoted as 1,000 kcmil, or 1,000 MCM. The terms "kcmil" and "MCM" are equivalent.

Conductor size 1/0 (106 kcmil) ACSR is commonly used for local feeder cable serving a limited area. The most common conductor sizes for larger feeders serving higher loads are 556 kcmil ASC, 336 kcmil ASC, and 3/0 AACSR. The latter is aluminum alloy conductor steel reinforced and is currently the standard neutral size because of its additional strength and performance over ACSR when combined field lashing of secondary conductors over top.

Load Interrupter Switches (LISs) are installed on both the 44kV subtransmission and the distribution voltage systems and are typically SCADA controlled in order to minimize outage durations by switching to restore power. Load Interrupter Switches and reclosers are installed in key locations that are determined based on system planning. The majority of protective devices on the lateral portions of the distribution system are fused switches that protect the system from faults and minimize the number of customers impacted.

Underground Feeder Design and Equipment Selection

The principal components of Veridian's underground distribution system include civil duct infrastructure, primary and secondary conductors, padmount transformers, and switchgear.

Veridian standards for underground equipment either meet or exceed Canadian Standard Association's "*CSA C22.3 No 7-10 Underground Systems"* standards, where those standards exist. Other internationally recognized standards, from the organizations listed above for overhead equipment, are used to supplement CSA where the CSA does not offer guidance.

The underground system can be divided into three tiers of descending size and load carrying requirements. System, or trunk, underground feeders are used where necessary (instead of overhead equipment, which is predominant) to carry large loads serving large areas and numbers of customers. The conductors used in this construction are 1,000 kcmil and are housed in concrete-encased ducts located in road allowances.

Main feeders are typically used in underground subdivision construction to carry major loads and interconnect switchgear units. Usually these are fed from overhead main system feeders and terminate at another main system feeder after passing through the subdivision. Conductors are carried through direct buried ducts in the road allowance and are typically 500 kcmil in size. These ducts are encased in concrete at corners and other vulnerable locations such as road crossings to prevent deformation of the duct which could impede or prevent timely replacement of the conductor in the event of a fault.

Local feeders are used to serve local loads and usually start and end at switchgear units. Conductors are carried through direct buried ducts in the road allowance and are typically 1/0 in size. Individual low voltage services are connected to local feeders, through nearby transformers.

For underground construction, padmounted transformers are used to step down primary supply voltage to secondary utilization voltage, and switchgear are used as connection (tap-off) points for system, main feeder and local primary cables and enable system fault protection and switching. De-energization of equipment is also sometimes necessary for maintenance or power restoration operations. The capacities of these units are dictated by the loads (actual and/or forecast) served or expected to be served by the equipment.

Copper stranded cable is used for primary voltages and aluminum stranded cable for secondary voltages. Primary underground cable is engineered to typically have multiple layers of insulating and semi-conducting material surrounding the central stranded core conductor with an overall outer jacket to withstand voltage stresses, eliminate the voltage gradient, and to prevent and protect from water ingress. Secondary underground cable does not have the same sophisticated design yet is still engineered with protective insulation for generally the same reasons.

Criteria for Construction Selection

When determining whether a feeder or segment of a feeder is to be overhead or underground, Veridian considers jurisdictional requirements, cost effectiveness, technical constraints, safety and reliability, and customer acceptance.

In order to carry out construction, Veridian must obtain permits from the regional or municipal authority with jurisdiction over the lands involved. To obtain permits, Veridian must comply with requirements imposed by these authorities, which may dictate a specific type of construction, or a specific physical location on the road allowance. Both of these requirements have an impact on the design and the cost.

The cost effectiveness of alternate styles of construction is influenced by many technical constraints, including topography, required spans and clearances, levels of voltage and load served, availability of land on which to site equipment including guy wires, and other factors. Underground construction is in most instances more expensive than overhead, due to the need for civil construction and placement of padmount transformers and switchgear to permit connection and maintenance. When not otherwise prevented from doing so, Veridian typically installs system feeders overhead with 50 metre spans between poles. For long required spans, such as those over highways, Veridian has begun to install engineered steel towers.

In newly developed residential areas, Veridian's standard construction has been, and continues to be, underground. Veridian's experience has been that municipalities, developers and residents do not accept overhead construction in these areas. Undergrounding these areas also protects equipment from vegetation which typically is or will be more prevalent than on arterial roads where main system feeders are located.

Attachment 4 of 5

Reliability in South Ajax - Overview of Projects

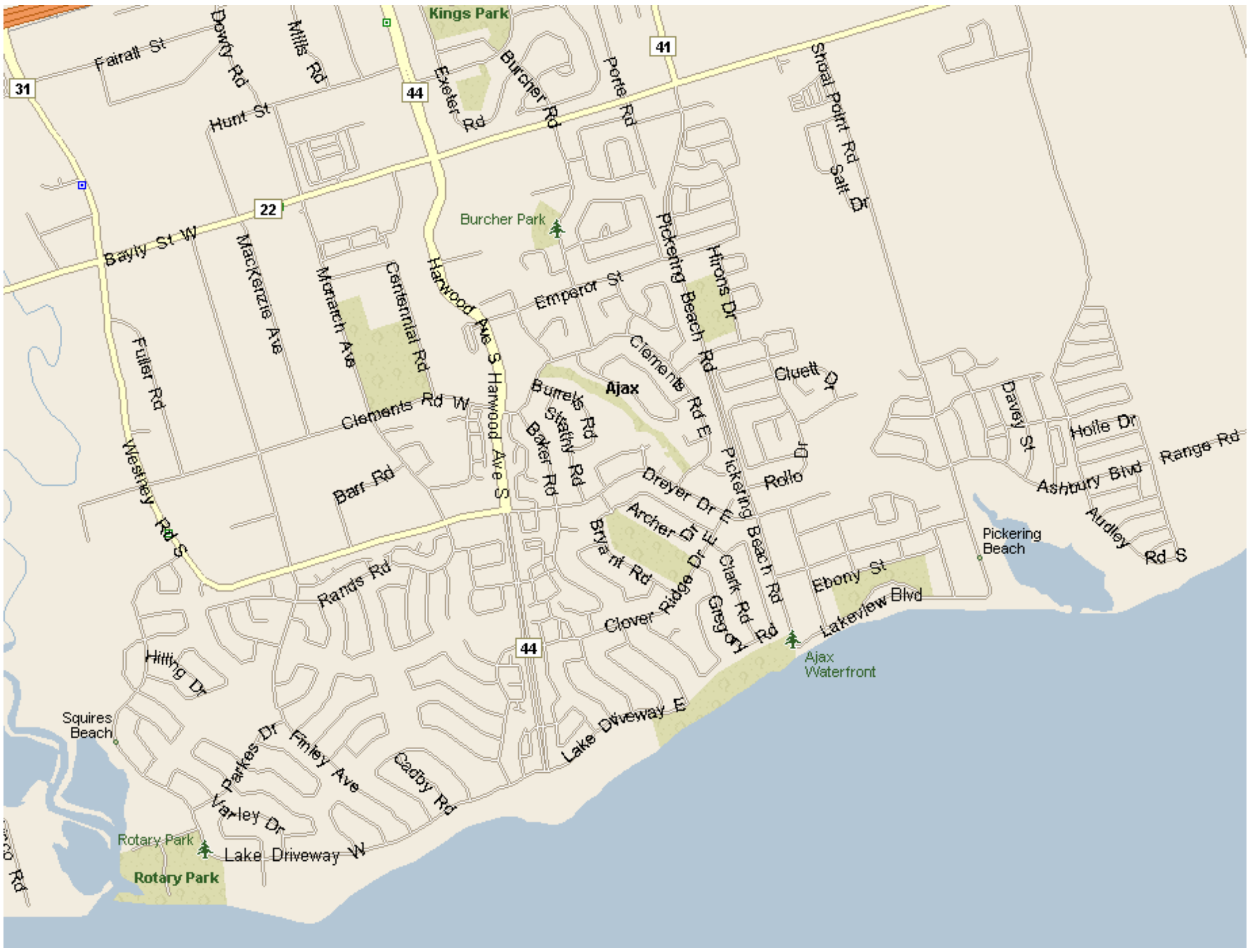
Reliability in South Ajax - Overview of Projects

The town of Ajax is one of the municipalities that Veridian serves, and the south Ajax area has for several years exhibited reliability problems that Veridian has taken a studied approach to address. In its 2010 application, Veridian led evidence concerning cable replacement projects and feeder automation initiatives it had undertaken in 2009 and was proposing for 2010. South Ajax has continued to be an area of focus for Veridian. This section of the evidence filed in this application provides an overview of reliability-related initiatives that Veridian has undertaken in south Ajax from 2010 to 2013, and proposes for 2014.

Background

The south Ajax area in question extends approximately from Lake Ontario to Bayly St (south of Highway 401), bordered on the west by Westney Road South and southerly extensions of that road, and on the east Audley Road South. Figure 1 below depicts the south Ajax area:

Figure 1: South Ajax Reliability Area



This area has been developed primarily for residential purposes, with supporting commercial development, starting in the late 1960’s through to the early 1980’s. It is served through a hierarchy of main (or trunk) feeders, local feeders, and services to individual properties, together with associated switchgear and transformers. Both overhead and underground infrastructure is present but most of the residential subdivisions are served by direct-buried underground cable of various vintages. The main feeders emanate from four substations (Monarch, Dowty, Pickering Beach, and Squires Beach) distributed across the area.

Reliability Degradations

While all distribution equipment has a finite life and eventually breaks down requiring replacement, the direct-buried underground cable in the south Ajax area has exhibited declining and/or poor performance for over a decade and is the root cause of most of the reliability degradation in the area. The direct-buried underground cable was installed in phases as lands were developed starting in the early 1970's, when cable materials and manufacturing processes were in early stages of development. Some segments of cable have been replaced over the last decade but there is still a significant portion of the system consisting of the equipment originally installed.

Degradation is now observed to be most pronounced, and reliability consequences are most severe, in the case of the main feeder cables. These cables carry the highest loads and serve the greatest number of customers. Local feeders are a step down the feeder hierarchy and typically serve small streets or sections of larger streets. While degradation has occurred and caused outages, the outages were more confined. Individual services are relatively lightly loaded and have experienced outages in isolated instances, but have not been generally problematic.
The equipment that the cable is integrated with (substations, switchgear, transformers, etc.) also exhibits varying vintages and conditions, and over time will require replacement in order to provide reliable service.

Approaches to Improving Reliability

The evidence pertaining to individual projects in this application provides details on the specific measures undertaken or proposed by Veridian in each case. However, in broad terms there are two alternative, but complementary approaches to improving reliability in cases where degradation is caused by failing underground cable: replacing or rehabilitating the cable itself, which over time removes the root cause of failure; and implementing feeder automation to mitigate the reliability impacts of failures which do occur.

One of the principal causes of cable failure is a phenomenon known as 'water-treeing'. This occurs when moisture ingresses into the cable sheathing and insulation, thereby impairing the di-electric properties of the insulation and making electrical faults possible. Under certain conditions, it is possible to inject a silicone-based substance into the cable, which migrates down the cable and blocks water-treeing. On a first-cost basis, cable injection is less expensive than cable replacement and can extend the effective working life of cables by 20 to 40 years, based on information provided by cable injection service providers. However, in many circumstances, it is not possible or effective to perform injection. Specifically, certain cable types such as solid conductor cable and strand blocked cable cannot accept injection. Of more relevance to Veridian, if a cable has been spliced in many locations such that the silicone fluid cannot travel a sufficient distance, injection becomes uneconomic. Finally, if the cable is badly corroded such that it must be replaced in any case injection becomes irrelevant.

In cases where injection is not possible or effective the only remaining option for addressing a failing cable segment is to replace it. Veridian no longer installs direct-buried feeder cables due to the inherent vulnerability of such cables to environmental factors which reduce their expected lifespans. Instead, feeder cables are installed in ducts which permit cables to be easily withdrawn for future repair or replacement and protect the cables from damage.

The determination of which approach (i.e., injection or replacement) should be taken in a particular location cannot be made without location-specific investigation and testing of the existing cable. However, Veridian will use injection in preference to replacement when injection is technically feasible and cost-effective.

Cable injection and/or replacement over a wide area is a time-consuming and relatively expensive process, and as such is generally undertaken over an extended period of time which can be ten or more years. However, with advances in electrical distribution system control technology, it has become possible to mitigate the reliability impacts of cable failures by re-configuring the electrical flows on the distribution system on a nearly instantaneous basis to minimize the load and number of customers affected by a cable fault. This process is commonly referred to as feeder automation.

Feeder automation relies on the installation of sensors and remotely controlled switches which, respectively, provide real-time system status information and the ability to switch electrical flows and isolate the smallest possible area affected by a cable fault. The switching and isolation is done automatically through sophisticated software which optimizes the system response given the physical configuration of the distribution system in the affected area. Feeder automation thus provides a vast improvement in reliability over the older system in which an outage might first have to be reported to the control room, and crews then dispatched to manually operate switches to isolate faulted feeder segments and restore power to un-faulted sections of the feeder.

While the benefits of feeder automation are desirable in any situation, it is particularly advantageous to implement feeder automation in circumstances where the underlying physical distribution system is at or near end of life and is exhibiting poor and worsening reliability performance. While feeder automation *per se* does not correct the underlying asset degradation, it can mitigate the reliability consequences of that degradation very substantially so that an orderly and gradual asset rehabilitation and/or replacement program can be conducted without unacceptable reliability impacts over an extended period.

Reliability-related Projects in the South Ajax Area

Veridian has undertaken a combined approach to resolving underground cable related reliability degradations in the south Ajax area. Veridian has substantially completed the feeder automation project for the area proposed in its 2010 application. In addition, Veridian has completed, or is completing the following cable replacement projects:

- 2012: Harwood Avenue South cable replacement
- 2012/2013: Finley Avenue cable replacement
- 2013: Barr Road cable replacement

Veridian plans to continue with cable replacement/rehabilitation projects in the south Ajax area over the IRM period as part of its Asset Condition Assessment related sustainment programs. In addition, two projects involving the Pickering Beach substation, which are primarily driven by capacity considerations, will prevent capacity-related reliability problems from occurring in the area.

All of these projects are separately documented in the corresponding project descriptions included in this evidence.

Attachment 5 of 5

AD34 Customer Complaint and Dispute Resolution Policy

1.0 GENERAL

Under the conditions of its *Electricity Distribution Licence*, Veridian Connections is obligated to establish administrative procedures for resolving complaints by consumers and other market participants. It also requires that a record of all written complaints be maintained, along with the related responses.

This policy details staff responsibilities in complying with these licence requirements.

2.0 DEFINITION OF A COMPLAINT

For the purpose of the record keeping provisions of this policy, a complaint must:

- Relate to service provided by Veridian Connections, and;
- Be received in writing, either by e-mail or hard copy, and;
- Contain an expression of dissatisfaction, or a formal allegation against a party.

Eligible complainants include all consumers and market participants that rely on the services of Veridian Connections. These include, but are not limited to electricity consumers, land developers, electricity retailers, embedded generators, and embedded distributors.

Note that routine claims for costs or reimbursement of expenses which are referred for disposition to our Insurer, MEARIE, are not considered complaints for the purpose of this policy. They may become a "complaint" if the claimant is dissatisfied with the outcome of the claim and lodges a written objection with Veridian.

3.0 COMPLAINT RESOLUTION

All staff has a responsibility to respond to customer complaints, either verbal or written, in a professional and ethical manner. Care must be taken not to be dismissive of a complaint, or a complainant. Respectful, timely and fact-based responses are to be provided in all circumstances.

The escalation of unresolved complaints shall normally be as follows:

- Front line staff
  - Field Supervisor/Supervisor
    - Manager
      - Executive Vice President
        - President and CEO
          - Ontario Energy Board

Staff may exercise judgment in applying this escalation procedure based on the unique circumstances relating to individual complaints, however, complaints should not be referred to the Ontario Energy Board without first being reviewed by the President and CEO. Customers may, of course, escalate a complaint to the Ontario Energy Board on their own initiative at any time.

Customers must also be apprised of the Dispute Resolution Procedure available to them under Section 1.8 of Veridian Connections' *Conditions of Service*. This document must be made available free of charge to any person who reasonably requests it.

4.0 RETAIL METER DISPUTES

For complaints regarding retail revenue meters, staff have an obligation to inform the customer of the assistance available by Measurement Canada in a dispute investigation. Measurement Canada has jurisdiction in a dispute between Veridian Connections and a customer, where the condition or registration of a meter or metering installation is in question.

5.0 COMPLAINT RECORD KEEPING

Under the Ontario Energy Board's *Reporting and Recording Keeping Requirements* for electricity distributors, Veridian Connections must maintain records of all written complaints and related responses for a period of two years. These records must include the following:

1. The name and address of the existing or prospective consumer;
2. A description of the nature of the complaint including a copy of the written complaint;
3. A description of the remedial action taken; and
4. A copy of any correspondence received and/or sent with respect to each specific complaint.

To facilitate the maintenance of this information, staff responding to a written complaint as defined under Section 2 of this policy shall provide copies of all correspondence to both the Executive Vice President and the Manager of Regulatory Affairs And Key Projects. On the basis of this information, the Manager of Regulatory Affairs And Key Projects shall maintain a record of all complaints in accordance with the Ontario Energy Board's requirements.

6.0 ANNUAL POLICY REVIEW

To ensure that this policy is consistently applied, it shall be reviewed annually with all Managers/Supervisors and frontline staff. This shall be initiated by the Manager Of Regulatory Affairs and implemented by the Executive Vice Presidents.

This annual review shall also include policy amendments as necessary to maintain consistency with the dispute resolution process detailed under Section 1.8 of Veridian Connections' *Conditions Of Service*.

System Capability Assessment for Renewable Energy Generation (REG)

Veridian has completed an extensive review of its distribution system for the purpose of determining the need for capital investments to accommodate the connection of REG projects. Veridian has determined, based on its experience regarding the number of applications received to-date, only one distribution system expansion is required to accommodate the connection of REG projects during the test year of 2014. The particular project is for an application for a 25.012 MW generation facility for Index Energy in Ajax, ON, scheduled for connection during 2014. Consultation with the Transmitter, Hydro One, has occurred for this generator connection and a Connection Cost Agreement is currently in place with the generator, covering both Veridian and Hydro One costs associated with the connection. Veridian's distribution system can currently accommodate the remaining and forecast applications through the test year without further capital investments. It is important to note that there are system constraints to the connection of REG projects within Veridian's service territory; however those constraints are located at Hydro One owned transformer stations.

Table 1 below outlines the number of greater than 10 KW REG applications Veridian has received, prepared connection-impact-assessments for, and connected to its distribution system since the inception of the Feed-in-Tariff program by the Ontario Power Authority (OPA) in 2009. The table is accurate to July 31, 2013 and the number of applications and connected kilowatts has been confirmed with the OPA.

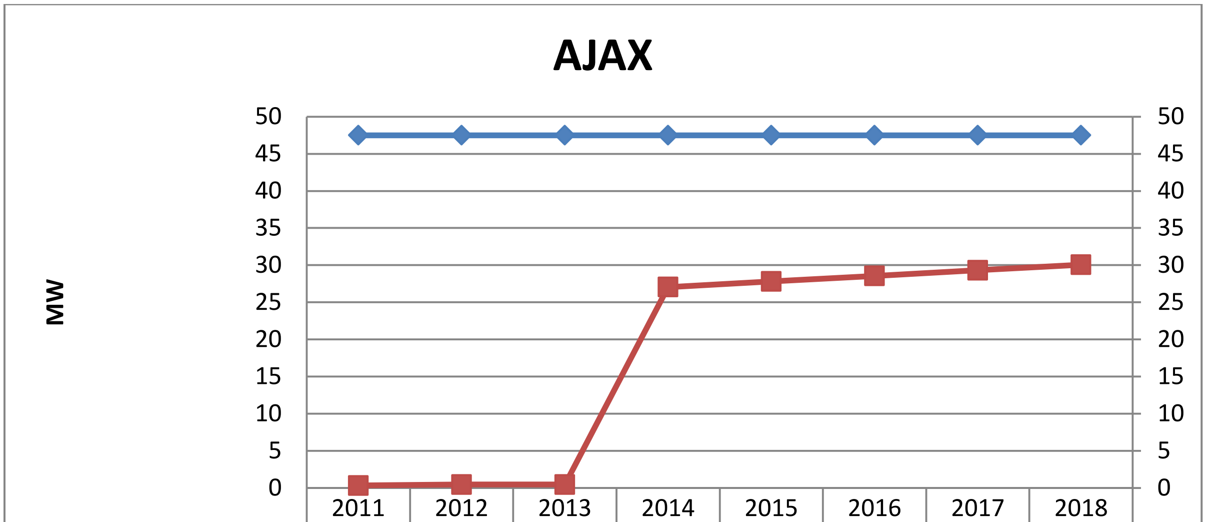
Table 1 – FIT Information – Veridian – 2009 to July 31, 2013

FIT	Connected	kW		Applications	kW		CIA Issued	kW
2009	0			8	26798		0	
2010	0			11	2564		3	976
2011	3	341		0	0		7	36082
2012	2	619		0	0		4	690
2013	3	590		15	2991		4	1260

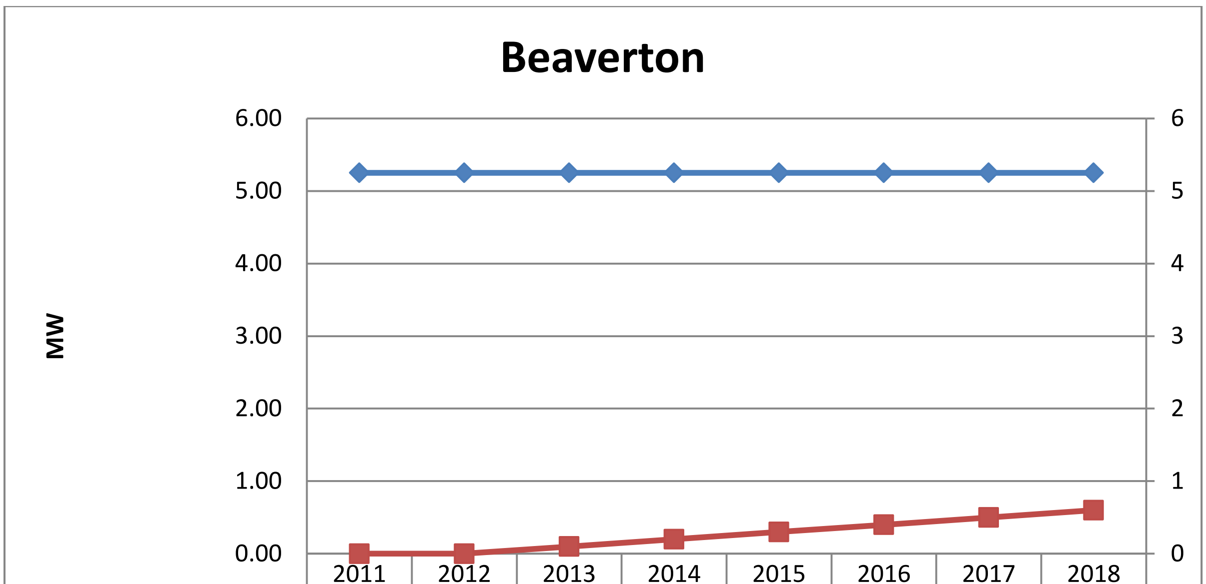
Table 1 – FIT Information – Veridian – 2009 to July 31, 2013

Table 1 indicates a greater quantity of CIAs issued versus applications received by Veridian. This anomaly occurred as a result of a generator application to Hydro One for a REG that will be embedded on Veridian's distribution system. Veridian was required to complete a CIA for the project; however the application for connection was made to Hydro One. The REG is 10 MW in size and is referred to as the Penn Energy project. There are connection costs associated with the REG, which will be recovered from Hydro One and ultimately the generator; however there is no expansion work required for Veridian's distribution system to accommodate the REG.

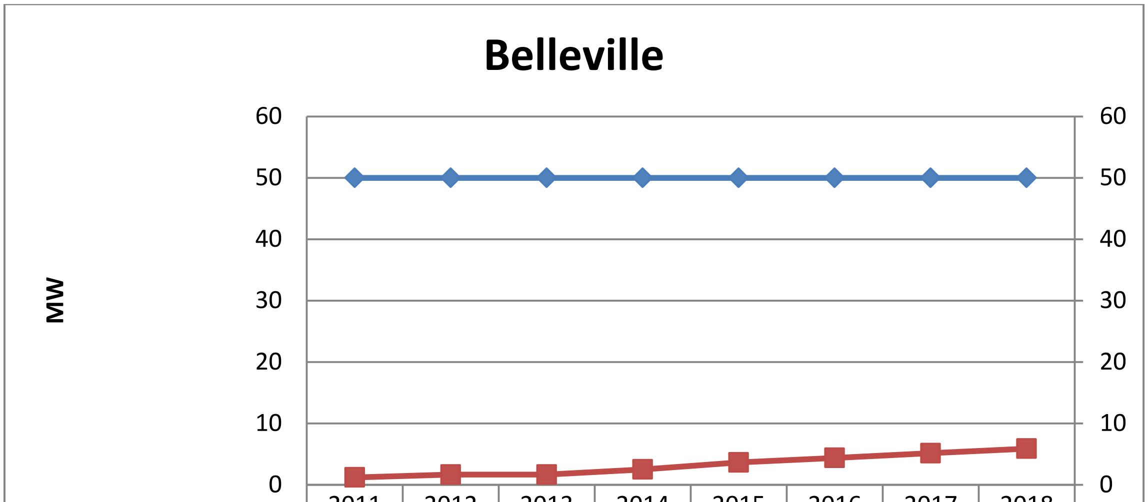
Veridian provides distribution services to 13 communities within Ontario. The graphs below are intended to provide graphical information for each community with regards to available capacity to connect REGs and current and projected REG connections for the rate application period. Available capacity to connect REGs includes current capacity availability at Hydro One owned transformer stations (TS) as of June 1. 2013.



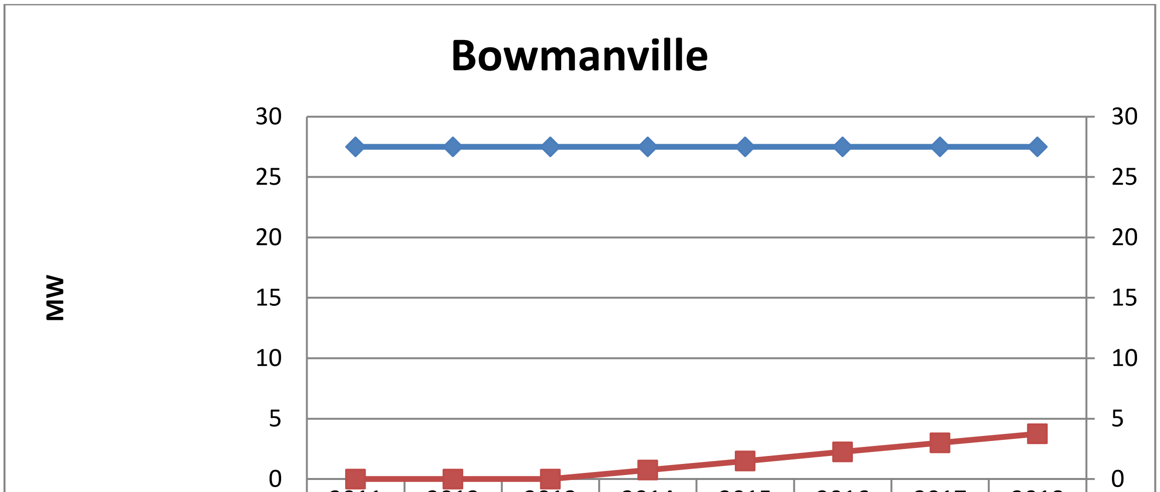
	2011	2012	2013	2014	2015	2016	2017	2018
Capacity(MW)	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5
Generators(MW)	0.326	0.461	0.461	27.061	27.811	28.561	29.311	30.061



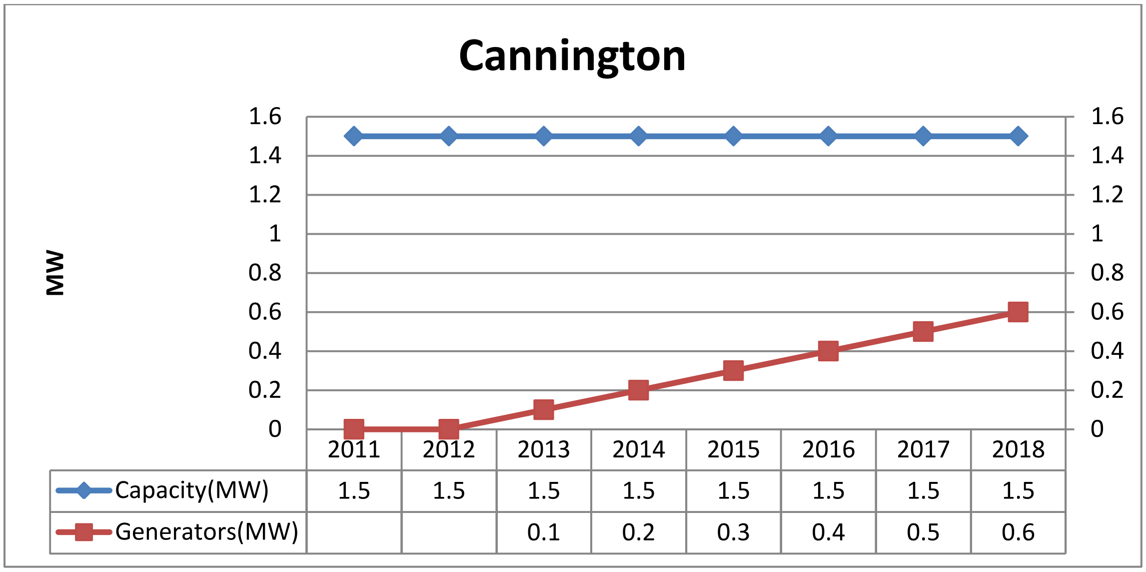
	2011	2012	2013	2014	2015	2016	2017	2018
Capacity(MW)	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25
Generators(MW)			0.10	0.20	0.30	0.40	0.50	0.60



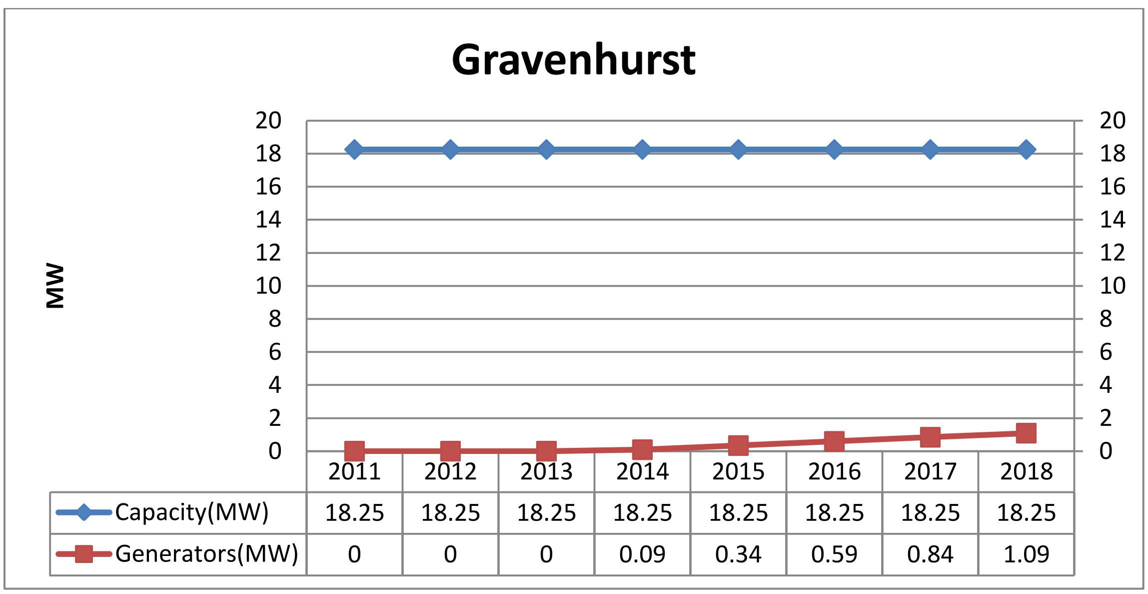
	2011	2012	2013	2014	2015	2016	2017	2018
Capacity(MW)	50	50	50	50	50	50	50	50
Generators(MW)	1.215	1.665	1.665	2.515	3.65	4.4	5.15	5.9



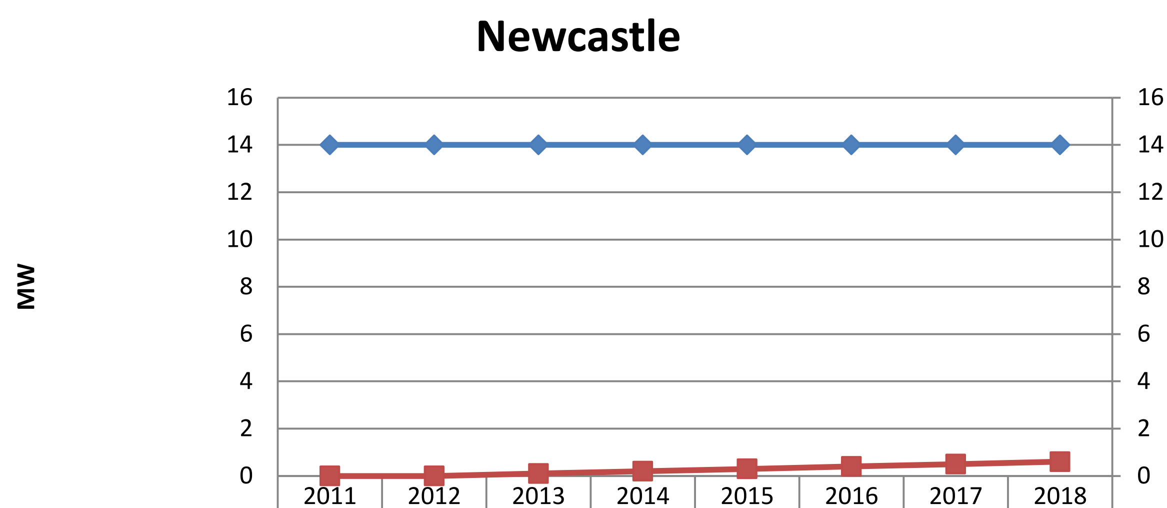
	2011	2012	2013	2014	2015	2016	2017	2018
Capacity(MW)	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5
Generators(MW)	0	0	0	0.75	1.5	2.25	3	3.75



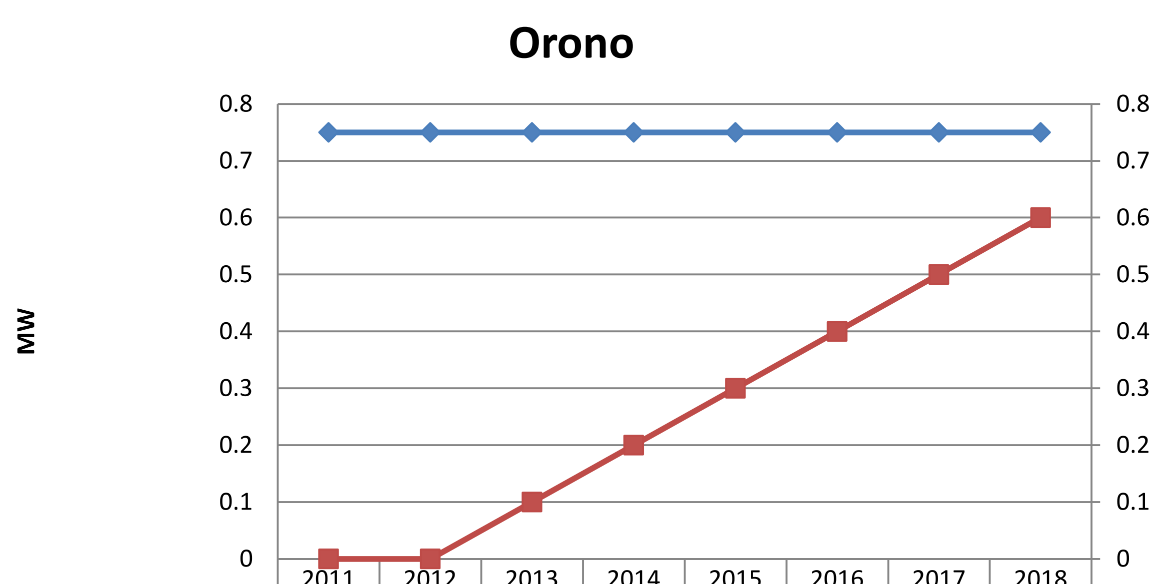
	2011	2012	2013	2014	2015	2016	2017	2018
Capacity(MW)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Generators(MW)			0.1	0.2	0.3	0.4	0.5	0.6



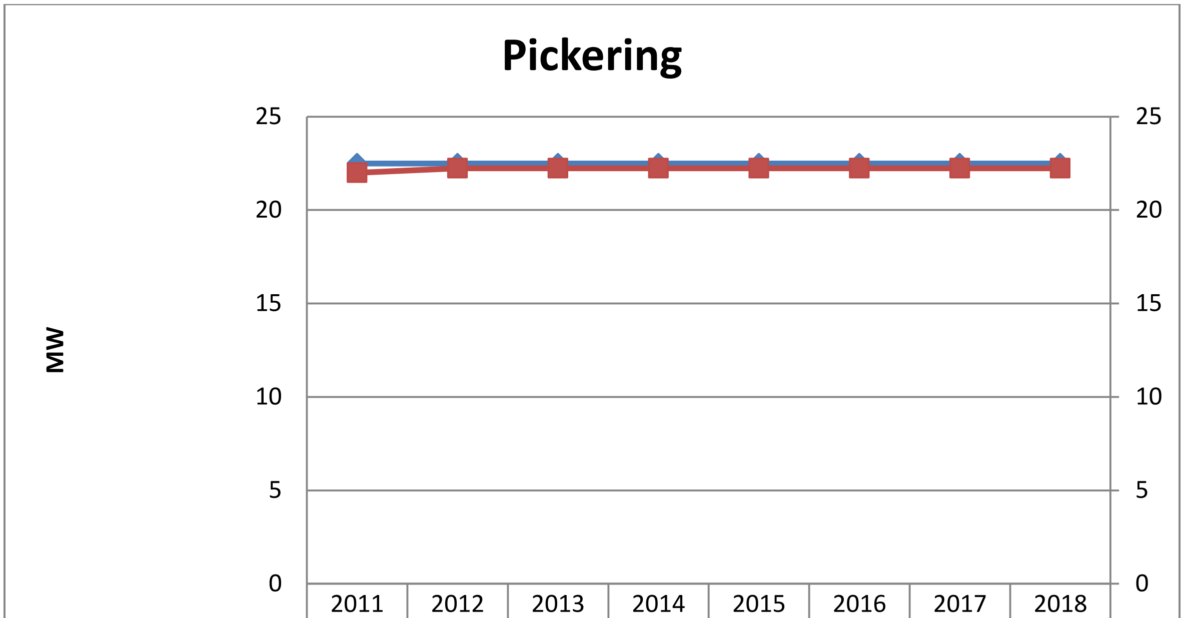
	2011	2012	2013	2014	2015	2016	2017	2018
Capacity(MW)	18.25	18.25	18.25	18.25	18.25	18.25	18.25	18.25
Generators(MW)	0	0	0	0.09	0.34	0.59	0.84	1.09



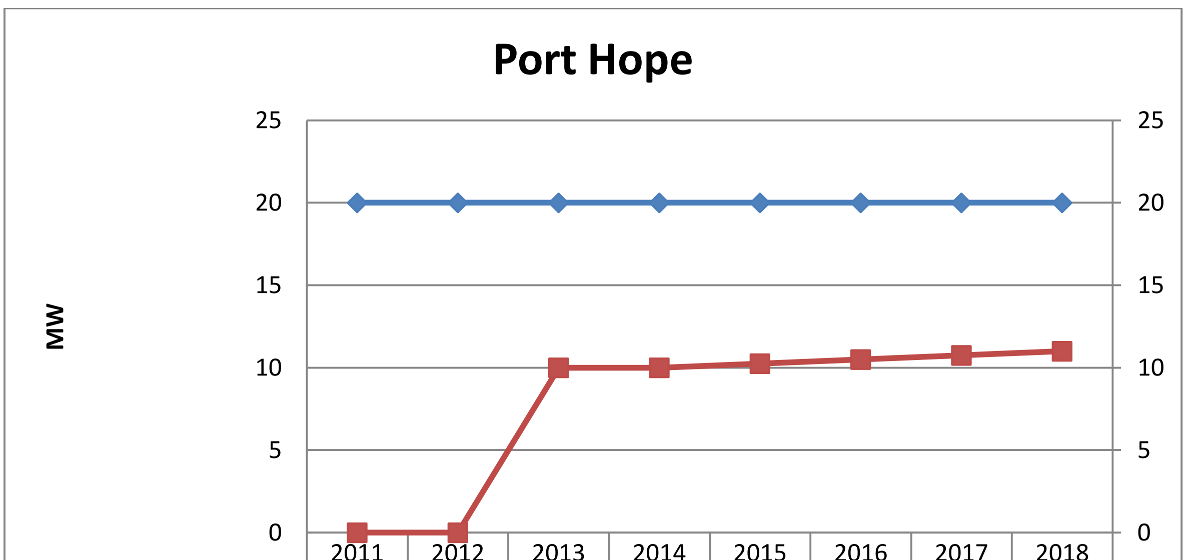
	2011	2012	2013	2014	2015	2016	2017	2018
Capacity(MW)	14	14	14	14	14	14	14	14
Generators(MW)			0.1	0.2	0.3	0.4	0.5	0.6



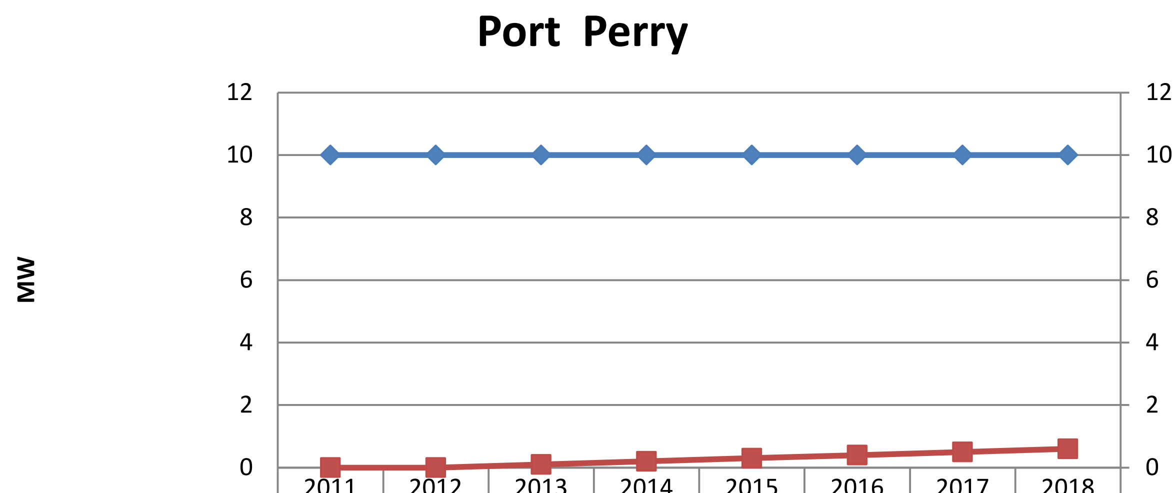
	2011	2012	2013	2014	2015	2016	2017	2018
Capacity(MW)	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Generators(MW)			0.1	0.2	0.3	0.4	0.5	0.6



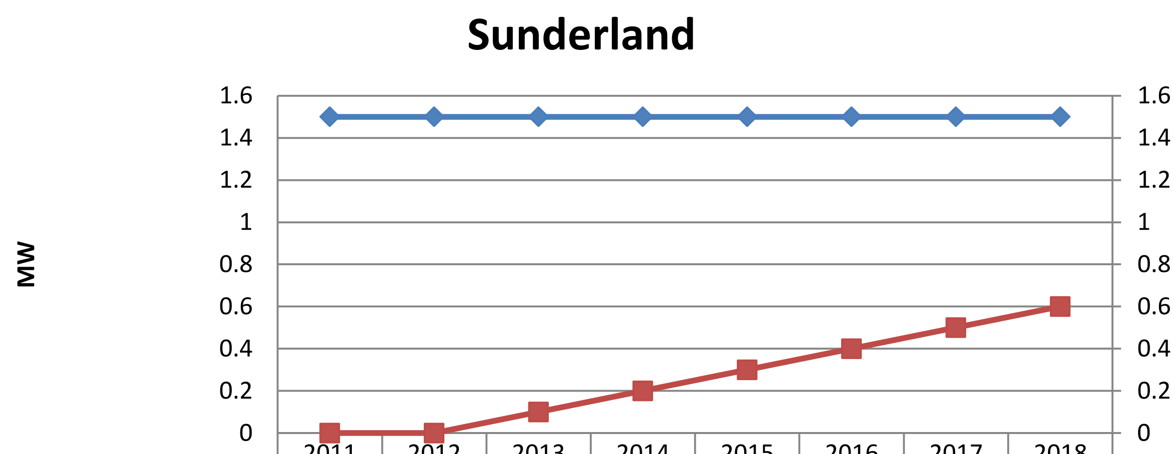
	2011	2012	2013	2014	2015	2016	2017	2018
Capacity(MW)	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5
Generators(MW)	22	22.24	22.24	22.24	22.24	22.24	22.24	22.24



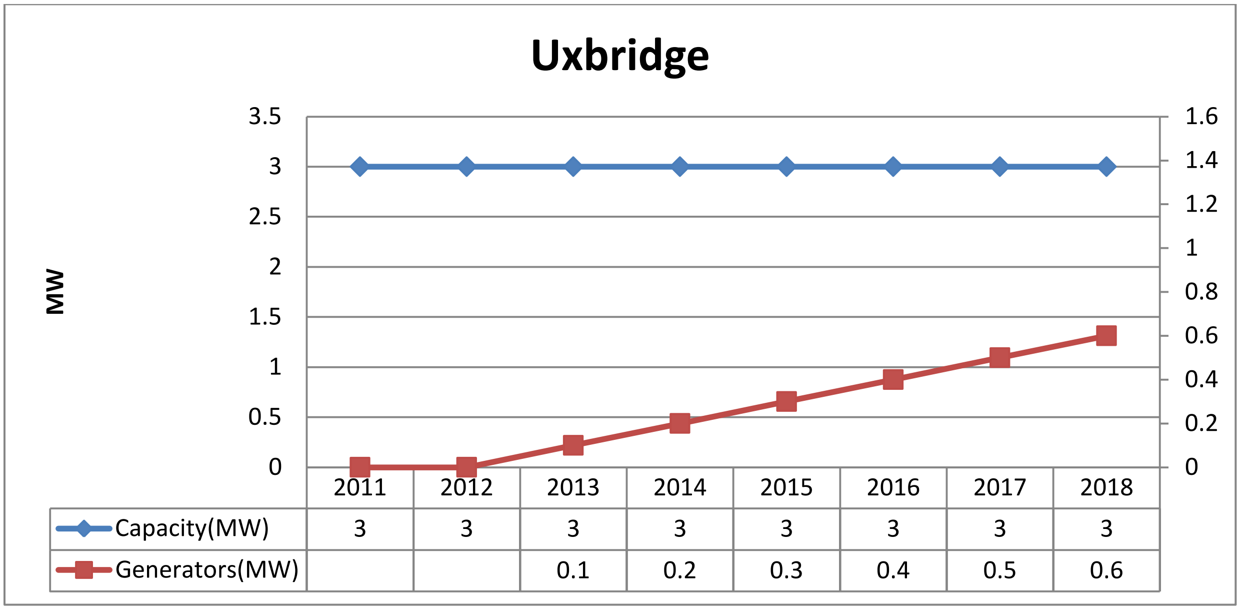
	2011	2012	2013	2014	2015	2016	2017	2018
Capacity(MW)	20	20	20	20	20	20	20	20
Generators(MW)	0	0	10	10	10.25	10.5	10.75	11



	2011	2012	2013	2014	2015	2016	2017	2018
Capacity(MW)	10	10	10	10	10	10	10	10
Generators(MW)			0.1	0.2	0.3	0.4	0.5	0.6



	2011	2012	2013	2014	2015	2016	2017	2018
Capacity(MW)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Generators(MW)			0.1	0.2	0.3	0.4	0.5	0.6



	2011	2012	2013	2014	2015	2016	2017	2018
Capacity(MW)	3	3	3	3	3	3	3	3
Generators(MW)			0.1	0.2	0.3	0.4	0.5	0.6

There are two noteworthy comments regarding capacity to connect REGs in Ajax and Pickering. The capacity to connect REGs as indicated in the Ajax graph above includes the capacity available following the distribution system enhancement required to connect the 25.012 MW Index Energy project. Veridian is currently constrained with regards to connecting REGs in its Pickering service territory due to Hydro One constraints at the Cherrywood TS. The Pickering graph above indicates this constraint and while Veridian expects to continue to receive applications for REGs, no new REGs will be connected until the constraint is addressed by Hydro One. The Veridian distribution system in Pickering has capacity to connect the expected REG applications during the period covered by this rate application.

Capital Expenditure Summary

Veridian's historic, bridge and test year capital investment needs are driven by a range of elements that impact the magnitude and composition of annual capital investment plans. A significant factor driving investments within the category of System Access is continued strong growth, particularly in the communities of Ajax, Pickering, Belleville and the Municipality of Clarington. This growth has driven substantial spending on customer connection projects and related line extensions and expansions, and is expected to remain a driver throughout the forecast period. Much of this growth is expected in north Pickering due to the Seaton community planned there. This development is forecast to require an investment of $21 million to construct a new transformer station to serve the north Pickering area. This project will be paced with the growth of the development and is currently planned for 2018.

The portfolio of System Access investments also continues to be driven by non-discretionary infrastructure development, primarily related to road relocations/widening undertaken to alleviate growing traffic volumes, implementation of transit system improvements and municipal infrastructure renewal programs. Veridian's work related to these projects is required by municipal, regional and provincial road authorities, and typically involves the relocation or replacement of existing distribution infrastructure. A significant project of this nature is the relocation work required to accommodate the expansion of Highway 407 further east. There is approximately $14 million (in gross capital spend) associated with that project alone.

System renewal spending is transitioning from a primarily reactive approach in the historical period, to one of a proactive plan informed by equipment condition information in the forecast period. These investments are driven, in part, by the findings of Veridian's first comprehensive

Asset Condition Assessment, which was completed in 2013. The assessment confirmed a need for a more proactive approach to asset renewal.

General Plant spending is projected to be at consistent levels over the forecast period. Earlier higher spending levels related to investments in facilities during the historical period are not anticipated to return.

System service spending is forecast to decline over the forecast period as spending is concentrated on System Access and System Renewal.

Attachment 1 of 5

Appendix 2-AB Summary of Capital Expenditures by Category (2009-14)

File Number:	EB-2013-0174
Exhibit:	2
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Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2014*

CATEGORY	**Historical Period** (previous plan[1] & actual)															**Forecast Period** (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access		3,836	--		6,670	--		9,475	--		20,246	--		17,769	--	27,258	13,315	15,869	11,323	34,018
System Renewal		5,106	--		3,003	--		2,499	--		6,418	--		6,215	--	14,120	14,372	11,441	12,527	10,117
System Service		6,995	--		3,681	--		7,644	--		6,992	--		5,937	--	1,623	63	275	1,013	-
General Plant		3,656	--		9,829	--		6,805	--		6,501	--		3,289	--	3,024	4,515	3,676	2,943	2,650
Less: Capital Contributions		- 3,715	--		- 2,595	--		- 5,788	--		- 6,007	--		- 9,525	--	- 15,334	- 5,547	- 5,472	- 5,472	- 5,472
TOTAL NET EXPENDITURE	-	15,878	--	-	20,589	--	-	20,635	--	-	34,149	--	-	23,685	--	30,691	26,719	25,790	22,335	41,314
System O&M		$ 6,418	--		$ 6,589	--		$ 7,085	--		$ 8,327	--		$ 8,955	--	$ 10,341	n/a	n/a	n/a	n/a

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 8 Note: 8 months actual in System O&M, 6 months actual in Capital categories.

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. histrical budgets by category

Notable in 2014 are higher than typical System Access spending levels. This is due to approximately $16 million in road relocation projects planned with the bulk of that spending related to the extension of Hwy 407. There is also a significant increase in spending in that category in 2018, due to an expected investment in a TS to serve the Seaton area in North Pickering. The new TS is forecast to come into service in 2018 at a cost of $21 million. System Renewal spending is significantly higher in the forecast period due to the implementation of Asset Condition Assessment related investments. System Renewal spending decreases somewhat over the forecast period as substation related projects are reduced later in the period. Lower than historical spending in System Service projects are noted in the forecast period due to the significant level of spending in the System Access and System Renewal categories. General Plant spending will be lower in the forecast period than the typical amount of spending in the historical period. Capital contributions are steady in forecast period as Veridian is anticipating a level amount of residential and GS connections.

Notes on year over year Plan vs. Actual variances for Total Expenditures

Not applicable- no previous DSP filed.

Notes on Plan vs. Actual variance trends for individual expenditure categories

Not applicable- no previous DSP filed.

Attachment 2 of 5

Appendix 2-AA Capital Investments by Project

2010 to 2014

File Number:	EB-2013-0174
Exhibit:	2
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Appendix 2-AA
Capital Projects Table

Projects	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
SYSTEM ACCESS							
New Residential Services	2,491,000	2,760,000	3,525,175	3,647,465	5,233,000	4,018,000	5,198,000
New GS Services	1,064,000	560,000	577,620	1,694,251	2,245,118	1,166,480	1,400,000
Retail Meters	258,000		390,000	430,000	653,541	479,000	454,500
Highway #11, Interchange, Gravenhurst Pole Line Relocation	551,000						
Kerrison Drive, Ajax Line Extension	283,900						
Line Relocation, Altona Road, Pickering			453,632				
Highway #7 Pole Line Relocation - Brock Road and Lakeridge			1,377,284				
Southeast Sewer Collector (SEC) Project			254,000	1,401,308		350,000	
GO Transit/City of Pickering - Pedestrian Bridge, Pickering				271,451			
Salem Road (Taunton Road to CPR)				325,000			
Salem Road Line Relocations (Rossland to Gillett)				494,303			
Rossland Road Relocations				257,526			
Brock Road Relocation (Rossland X CPR Tracks)					772,990		
Brock St West Joint Feeder Extension-Uxbridge					367,317	600,000	
Brock Road Relocation (Bayly St to Kingston Rd) - Pickering					439,408		
Bayly Street Relocation (Shoal Point Road to Lakeridge) - Ajax					951,559		
Pickering Parkway Relocation - Pickering					490,973		
Cherrywood Wholesale Meter Upgrade					496,280		
New CN Rail Crossing, Belleville					241,105		
Smart Meters transferred from Variance Account					7,067,812		
LTLT Eliminations - Various Locations						650,000	600,000
College Street Extension- Belleville						294,000	
Highway 407 Extension - Various Road Relocations						5,288,241	8,757,553
Highway #2 Road Widening - Bus Rapid Transit-Phases 1 & 2						1,023,787	2,251,700
Westney Road Relocation (Magill X Telford), Ajax						1,475,000	
Rossland Road Relocation (Clearside X Southcott), Ajax						385,000	
Line Relocation, Orono Creek, Clarington						258,000	85,000
Relocation of 44 kV Pole Line, Port Hope							625,000
New REG Connection, Ajax							700,000
Three 27.6 kV circuits-Taunton Road (Church to Brock)							1,331,998
O/H Line Extension - Airport Parkway West, Belleville							306,600
Rossland Road (Southcott to Church)							736,000
Feeder Relocation, Front Street (Dundas X Pinnacle), Belleville							1,979,219
Dundas Street (Coleman to Baybridge)							2,200,136
Sub-Total Material Projects	4,647,900	3,320,000	6,577,711	8,521,304	18,959,103	15,987,508	26,625,706
Miscellaneous Projects (under materiality threshold)		516,148	92,719	953,499	1,286,904	1,781,500	632,321
Total System Access		**3,836,148**	**6,670,430**	**9,474,803**	**20,246,007**	**17,769,008**	**27,258,027**
SYSTEM RENEWAL							
Reactive Pole Replacements	787,000	848,330	568,206	611,047	666,000	752,000	752,000
Reactive Transformer and Component Replacements	816,000	1,527,472	1,334,260	669,224	1,400,865	900,000	900,000
Reactive Pole Rework (reinsulating and reframing)	809,800	532,522			442,000		
Old Kingston Road Conversion				293,402			
South Ajax Cable Replacement - Finley Avenue					1,538,707	1,875,000	
Storm Damage Rebuild - Gravenhurst July 2013						799,000	
New Feeder - Croft Street, Port Hope							357,000
Substations Transformer Replacement, Greenwood Substation							713,000
Substation Transformer Replacement and Component Upgrades- Fairport SS							2,434,500
Substation Transformer Spare Replenishment							900,000
Padmounted Switchgear Replacement program, various locations							900,000
Substation Breakers Replacement, Toronto Substation							600,000
Wood Pole Replacement Program, various locations							2,041,986
Primary Cable Rehabilitation Program, various locations							1,000,000
Polemount Transformer Replacement Program, various							736,000
Overhead Line Switch Replacement Program, various							706,000
Padmount Transformers Replacement Program, various							800,000
Sub-Total Material Projects	2,412,800	2,908,324	1,902,466	1,573,673	4,047,572	4,326,000	12,840,486
Miscellaneous Projects (under materiality threshold)		2,197,695	1,100,499	925,130	2,369,937	1,888,800	1,279,100
Total System Renewal		**5,106,019**	**3,002,965**	**2,498,803**	**6,417,509**	**6,214,800**	**14,119,586**
SYSTEM SERVICE							
Jane Forrester Park Phase 1 and 2, Belleville	272,400	405,000					
27.6 KV TS Egress Feeders (4) Hydro One Whitby TS#2, Ajax	2,520,000						
Salem Road-2nd Circuit 44 kV-Kingston Road to Rossland Road	412,000						

LIS Automation, Belleville	809,800						
Duffin Creek WPCP 44 kV Circuit, Ajax	837,000			328,490	908,690		
Pole Line Relocation - Bell Blvd		738,021					
Substation Oil Containment		337,022	617,157				300,000
Whitby TS 27.6 kV Switching Phase 1 and 2		398,785		431,000			
Lakeridge Road		294,618					
27.6kV Feeders Rossland Rd (Lakeridge to Westney), Ajax		248,370					
Sidney St. Substation, Belleville		546,159					
SCADA Reactive Repairs		298,891					
Pole line rebuild, Cavan Street, Port Hope		357,621					
LIS Installations		247,495	424,061				
South Ajax Feeder Automation		1,670,000		144,000	1,243,000		
Whitby TS Feeders (Part 1 and 2) Lakeridge Road, Rossland Rd, Ajax		300,000	502,879				
Cannington Substation (Relocation and Replacement)				2,038,274	445,724		
Liberty Street North Substation Upgrade, Bowmanville				1,779,102			
Feeder rebuild, Dixie Rd, Pickering				667,190			
Feeder rebuild, Edgehill Road, Belleville				719,897			
Feeder rebuild, Moira Street and Palmer Rd, Belleville				702,289			
SCADA System Replacement / Upgrade						601,000	
Wilmot Substation Upgrade, Newcastle						1,900,000	
Pickering Beach Substation Upgrade, Ajax						2,121,000	
Voltage Conversion - 4.16kV First Street (First X James), Gravenhurst						450,400	432,400
New Feeder-13.8 kV Loop Feed, Port of Newcastle, Newcastle							444,000
Sub-Total Material Projects	4,851,200	5,841,982	1,544,097	6,810,242	2,597,414	5,072,400	1,176,400
Miscellaneous Projects (under materiality threshold)		1,153,287	2,137,188	834,104	4,394,151	865,000	446,900
Total System Service		**6,995,269**	**3,681,285**	**7,644,346**	**6,991,565**	**5,937,400**	**1,623,300**
GENERAL PLANT							
General Plant - Facilities							
Leasehold Improvements, Pickering		260,335					
Building Expansion, 55 Taunton Road East, Ajax			5,759,784	2,259,000			
Building Renovations and Control Room Relocation, Ajax				2,115,882			
General Plant - Fleet							
Vehicles (2 large bucket trucks)		495,467					
Vehicles (3 medium duty trucks, 2 hybrids)			1,757,360				
Vehicles (1 large bucket truck)				268,235			
Vehicles (1 large bucket truck)					305,301		
Vehicles (1 large bucket truck)							400,000
General Plant - Information Technology							
GIS Computer Software	1,390,000		159,000	238,000	426,000	140,000	150,000
Server Virtualization		369,044					
Outage Management System		555,750					
Desktop Replacements		234,530					
Mobile Computing			50,000		402,619	400,000	300,000
GIS Data Conversion and Collection Gravenhurst - Phase 1 and 2			396,863		258,360		
Electronic Document Management and Records Classification					254,601		
Design and Construction Standards Development					263,118		
GIS Records Management - General					336,504		
Unified Messaging - Phone System Replacement, Phases 1 and 2						451,000	60,000
High Availability Data Site						350,000	
Business Continuity/Disaster Recovery Site							200,000
Renewable Generation Asset					835,949		
Sub-Total Material Projects	1,390,000	1,915,126	8,123,007	4,881,117	3,082,452	1,341,000	1,110,000
Miscellaneous Projects (under materiality threshold)		1,740,543	1,706,034	1,924,138	4,254,659	1,947,500	1,914,000
Total General Plant		3,655,669	9,829,041	6,805,255	7,337,111	3,288,500	3,024,000
Total all Categories - including Renewable Generation		**19,593,105**	**23,183,721**	**26,423,207**	**40,992,192**	**33,209,708**	**46,024,913**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*					-835,949		
Total	**18,734,042**	**19,593,105**	**23,183,721**	**26,423,207**	**40,156,243**	**33,209,708**	**46,024,913**

Note:

1) All Project amounts are gross dollars and do not reflect Capital Contributions Received

2) Total Capital in 2008 has not been recast by category, therefore, totals by category are not available - Total of Capital Program has been provided

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category.

Attachment 3 of 5

Appendix 2-FA Renewable Generation Connection Investment Summary

File Number:	EB-2013-0174
Exhibit:	2
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Appendix 2-FA
Renewable Generation Connection Investment Summary (over the rate setting period)

Enter the details of the Renewable Generation Connection projects as described in Section 2.5.2.5 of the Filing Requirements.
All costs entered on this page will be transferred to the appropriate cells in the appendices that follow.

For Part A, Renewable Enabling Improvements (REI), these amounts will be transferred to Appendix 2 - FB

For Part B, Expansions, these amounts will be transferred to Appendix 2 - FC

If there are more than **five** projects proposed to be in-service in a certain year, please amend the tables below and ensure that the formulae for the Total Amounts in any given rate year are updated.
Based on the current methodology and allocation, amounts allocated represent 6% for REI Connection Investments and 17% for Expansion Investments. (pg 15, EB-2009-0349)

Part A

REI Investments (Direct Benefit at 6%)	2014	2015	2016	2017	2018
Project 1					
Name: Communication Platform					
Capital Costs	$0	$115,000	$115,000	$115,000	$115,000
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$66,700	$66,700	$66,700	$66,700
Project 2					
Name: Micro-Grid Project					
Capital Costs	$0	$300,000	$165,000	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$50,000	$50,000	$50,000
Project 3					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 4					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 5					
Name: REI Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ 415,000**	**$ 280,000**	**$ 115,000**	**$ 115,000**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ 66,700**	**$ 116,700**	**$ 116,700**	**$ 116,700**

Part B

Expansion Investments (Direct Benefit at 17%)	2014	2015	2016	2017	2018
Project 1					
Name: Index Energy Expansion					
Capital Costs	$500,000	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 2					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 3					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 4					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Project 5					
Name: Expansion Connection Project					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Total Capital Costs	**$ 500,000**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Attachment 4 of 5

Appendix 2-FB Calculation of Renewable Generation Connection Direct Benefits/Provincial Amounts

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Appendix 2-FB
Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
Rate Riders are not calculated for Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2014 Test Year			2015			2016			2017			2018		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)		$ -	$ -	$ -	$ 197,125	$ 11,828	$ 185,298	$ 506,500	$ 30,390	$ 476,110	$ 638,625	$ 38,318	$ 600,308	$ 672,625	$ 40,358	$ 632,268
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$66,700	$ 66,700		$116,700	$ 116,700		$116,700	$ 116,700		$116,700	$ 116,700	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	13.80%		$ -	$ -		$ 9,205	$ -		$ 16,105	$ -		$ 16,105	$ -		$ 16,105	$ -
Rate Base			$ -	$ -		$ 21,032	$ 185,298		$ 46,495	$ 476,110		$ 54,422	$ 600,308		$ 56,462	$ 632,268
Deemed ST Debt	4%		$ -	$ -		$ 841	$ 7,412		$ 1,860	$ 19,044		$ 2,177	$ 24,012		$ 2,258	$ 25,291
Deemed LT Debt	56%		$ -	$ -		$ 11,778	$ 103,767		$ 26,037	$ 266,622		$ 30,476	$ 336,172		$ 31,619	$ 354,070
Deemed Equity	40%		$ -	$ -		$ 8,413	$ 74,119		$ 18,598	$ 190,444		$ 21,769	$ 240,123		$ 22,585	$ 252,907
ST Interest	2.07%		$ -	$ -		$ 17	$ 153		$ 38	$ 394		$ 45	$ 497		$ 47	$ 524
LT Interest	5.10%		$ -	$ -		$ 601	$ 5,292		$ 1,328	$ 13,598		$ 1,554	$ 17,145		$ 1,613	$ 18,058
ROE	8.98%		$ -	$ -		$ 755	$ 6,656		$ 1,670	$ 17,102		$ 1,955	$ 21,563		$ 2,028	$ 22,711
Cost of Capital Total			$ -	$ -		$ 1,374	$ 12,101		$ 3,036	$ 31,094		$ 3,554	$ 39,205		$ 3,687	$ 41,292
OM&A			$ -	$ -		$ 66,700	$ -		$ 116,700	$ -		$ 116,700	$ -		$ 116,700	$ -
Amortization		$ -	$ -	$ -	$ 20,750	$ 1,245	$ 19,505	$ 55,500	$ 3,330	$ 52,170	$ 75,250	$ 4,515	$ 70,735	$ 86,750	$ 5,205	$ 81,545
Grossed-up PILs			$ -	$ -		$ 462	$ 5,365		$ 1,162	$ 14,930		$ 1,600	$ 21,799		$ 1,934	$ 27,029
Revenue Requirement			$ -	$ -		$ 69,780	$ 36,972		$ 124,228	$ 98,194		$ 126,369	$ 131,739		$ 127,526	$ 149,866
Provincial Rate Protection				$ -			$ 36,972			$ 98,194			$ 131,739			$ 149,866
Monthly Amount Paid by IESO				$ -			$ 3,081			$ 8,183			$ 10,978			$ 12,489

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis

Note 2: For the 2014 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

	2014		2015		2016			2017			2018	
Income Tax	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
							Total			Total		
Net Income - ROE on Rate Base	$ -	$ -	$ 755	$ 6,656	$ 1,670	$ 17,102		$ 1,955	$ 21,563		$ 2,028	$ 22,711
Amortization (6% DB and 94% P)	$ -	$ -	$ 1,245	$ 19,505	$ 3,330	$ 52,170		$ 4,515	$ 70,735		$ 5,205	$ 81,545
CCA (6% DB and 94% P)	$ -	$ -	-$ 720	-$ 11,280	-$ 1,778	-$ 27,862		-$ 2,032	-$ 31,837		-$ 1,870	-$ 29,290
Taxable income	$ -	$ -	$ 1,280	$ 14,881	$ 3,222	$ 41,410		$ 4,438	$ 60,461		$ 5,364	$ 74,966
Tax Rate (to be entered)	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%		26.50%	26.50%		26.50%	26.50%
Income Taxes Payable	$ -	$ -	$ 339.33	$ 3,943.43	$ 853.75	$ 10,973.72		$ 1,175.99	$ 16,022.26		$ 1,421.34	$ 19,866.07
Gross Up												
Income Taxes Payable	$ -	$ -	$ 461.67	$ 5,365.22	$ 1,161.56	$ 14,930.23		$ 1,599.99	$ 21,799.00		$ 1,933.80	$ 27,028.67
Grossed Up PILs	**$ -**	**$ -**	**$ 462**	**$ 5,365**	**$ 1,162**	**$ 14,930**		**$ 1,600**	**$ 21,799**		**$ 1,934**	**$ 27,029**

		2014	2015	2016	2017	2018
Net Fixed Assets						
Enter applicable amortization in years:	10					
Opening Gross Fixed Assets			$ -	$ 415,000	$ 695,000	$ 810,000
Gross Capital Additions		$ -	$ 415,000	$ 280,000	$ 115,000	$ 115,000
Closing Gross Fixed Assets		$ -	$ 415,000	$ 695,000	$ 810,000	$ 925,000
Opening Accumulated Amortization			$ -	$ 20,750	$ 76,250	$ 151,500
Current Year Amortization (before additions)			$ -	$ 41,500	$ 69,500	$ 81,000
Additions (half year)		$ -	$ 20,750	$ 14,000	$ 5,750	$ 5,750
Closing Accumulated Amortization		$ -	$ 20,750	$ 76,250	$ 151,500	$ 238,250
Opening Net Fixed Assets		$ -	$ -	$ 394,250	$ 618,750	$ 658,500
Closing Net Fixed Assets		$ -	$ 394,250	$ 618,750	$ 658,500	$ 686,750
Average Net Fixed Assets		$ -	$ 197,125	$ 506,500	$ 638,625	$ 672,625

UCC for PILs Calculation

		2014	2015	2016	2017	2018
Opening UCC			$ -	$ 288,000	$ 423,360	$ 389,491
Capital Additions (from Appendix 2-FA)		$ -	$ 300,000	$ 165,000	$ -	$ -
UCC Before Half Year Rule		$ -	$ 300,000	$ 453,000	$ 423,360	$ 389,491
Half Year Rule (1/2 Additions - Disposals)		$ -	$ 150,000	$ 82,500	$ -	$ -
Reduced UCC		$ -	$ 150,000	$ 370,500	$ 423,360	$ 389,491
CCA Rate Class (to be entered)	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%
CCA		$ -	$ 12,000	$ 29,640	$ 33,869	$ 31,159
Closing UCC		$ -	$ 288,000	$ 423,360	$ 389,491	$ 358,332

Attachment 5 of 5

Appendix 2-FC Calculation of Renewable Generation Connection Direct Benefits/Provincial Amounts

File Number:	EB-2013-0174
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Tab:	3
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Appendix 2-FC

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Expansion Investments

This table will calculate the distributor/provincial shares of the investments entered in Part B of Appendix 2-FA.

Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.

Rate Riders are not calculated for Test Year as these assets and costs are already in the distributors rate base.

		2014 Test Year			2015			2016			2017			2018		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	17%	83%	Total	17%	83%	Total	17%	83%	Total	17%	83%	Total	17%	83%
Net Fixed Assets (average)		$ 246,875	$ 41,969	$ 204,906	$ 487,500	$ 82,875	$ 404,625	$ 475,000	$ 80,750	$ 394,250	$ 462,500	$ 78,625	$ 383,875	$ 450,000	$ 76,500	$ 373,500
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	13.80%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ 41,969	$ 204,906		$ 82,875	$ 404,625		$ 80,750	$ 394,250		$ 78,625	$ 383,875		$ 76,500	$ 373,500
Deemed ST Debt	4%		$ 1,679	$ 8,196		$ 3,315	$ 16,185		$ 3,230	$ 15,770		$ 3,145	$ 15,355		$ 3,060	$ 14,940
Deemed LT Debt	56%		$ 23,503	$ 114,748		$ 46,410	$ 226,590		$ 45,220	$ 220,780		$ 44,030	$ 214,970		$ 42,840	$ 209,160
Deemed Equity	40%		$ 16,788	$ 81,963		$ 33,150	$ 161,850		$ 32,300	$ 157,700		$ 31,450	$ 153,550		$ 30,600	$ 149,400
ST Interest	2.07%		$ 35	$ 170		$ 69	$ 335		$ 67	$ 326		$ 65	$ 318		$ 63	$ 309
LT Interest	5.10%		$ 1,199	$ 5,852		$ 2,367	$ 11,556		$ 2,306	$ 11,260		$ 2,246	$ 10,963		$ 2,185	$ 10,667
ROE	8.98%		$ 1,508	$ 7,360		$ 2,977	$ 14,534		$ 2,901	$ 14,161		$ 2,824	$ 13,789		$ 2,748	$ 13,416
Cost of Capital Total			$ 2,741	$ 13,382		$ 5,412	$ 26,425		$ 5,274	$ 25,748		$ 5,135	$ 25,070		$ 4,996	$ 24,393
OM&A			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ 6,250	$ 1,063	$ 5,188	$ 12,500	$ 2,125	$ 10,375	$ 12,500	$ 2,125	$ 10,375	$ 12,500	$ 2,125	$ 10,375	$ 12,500	$ 2,125	$ 10,375
Grossed-up PILs			-$ 299	-$ 1,461		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement			$ 3,504	$ 17,108		$ 7,537	$ 36,800		$ 7,399	$ 36,123		$ 7,260	$ 35,445		$ 7,121	$ 34,768
Provincial Rate Protection				$ 17,108			$ 36,800			$ 36,123			$ 35,445			$ 34,768
Monthly Amount Paid by IESO				$ 1,426			$ 3,067			$ 3,010			$ 2,954			$ 2,897

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.
Note 2: For the 2014 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

	2014		2015		2016			2017			2018	
Income Tax	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
							Total			Total		
Net Income - ROE on Rate Base	$ 1,508	$ 7,360	$ 2,977	$ 14,534	$ 2,901	$ 14,161		$ 2,824	$ 13,789		$ 2,748	$ 13,416
Amortization (17% DB and 83% P)	$ 1,063	$ 5,188	$ 2,125	$ 10,375	$ 2,125	$ 10,375		$ 2,125	$ 10,375		$ 2,125	$ 10,375
CCA (17% DB and 83% P)	-$ 3,400	-$ 16,600	-$ 6,528	-$ 31,872	-$ 6,006	-$ 29,322		-$ 5,525	-$ 26,976		-$ 5,083	-$ 24,818
Taxable income	-$ 830	-$ 4,052	-$ 1,426	-$ 6,963	-$ 980	-$ 4,786		-$ 576	-$ 2,813		-$ 210	-$ 1,027
Tax Rate (to be entered)	26.50%	26.50%										
Income Taxes Payable	-$ 219.95	-$ 1,073.85	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Gross Up												
Income Taxes Payable	-$ 299.25	-$ 1,461.02	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Grossed Up PILs	-$ 299	-$ 1,461	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -

Net Fixed Assets		2014	2015	2016	2017	2018
Enter applicable amortization in years:	40					
Opening Gross Fixed Assets			$ 500,000	$ 500,000	$ 500,000	$ 500,000
Gross Capital Additions		$ 500,000	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets		$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
Opening Accumulated Amortization			$ 6,250	$ 18,750	$ 31,250	$ 43,750
Current Year Amortization (before additions)			$ 12,500	$ 12,500	$ 12,500	$ 12,500
Additions (half year)		$ 6,250	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ 6,250	$ 18,750	$ 31,250	$ 43,750	$ 56,250
Opening Net Fixed Assets		$ -	$ 493,750	$ 481,250	$ 468,750	$ 456,250
Closing Net Fixed Assets		$ 493,750	$ 481,250	$ 468,750	$ 456,250	$ 443,750
Average Net Fixed Assets		$ 246,875	$ 487,500	$ 475,000	$ 462,500	$ 450,000

UCC for PILs Calculation

		2014	2015	2016	2017	2018
Opening UCC			$ 480,000	$ 441,600	$ 406,272	$ 373,770
Capital Additions (from Appendix 2-FA)		$ 500,000	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ 500,000	$ 480,000	$ 441,600	$ 406,272	$ 373,770
Half Year Rule (1/2 Additions - Disposals)		$ 250,000	$ -	$ -	$ -	$ -
Reduced UCC		$ 250,000	$ 480,000	$ 441,600	$ 406,272	$ 373,770
CCA Rate Class (to be entered)	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%
CCA		$ 20,000	$ 38,400	$ 35,328	$ 32,502	$ 29,902
Closing UCC		$ 480,000	$ 441,600	$ 406,272	$ 373,770	$ 343,869

Overall Capital Plan - Justification

This section of Veridian's Distribution System Plan (DSP) provides information to support the planned capital investment levels assigned to each investment category. The impacts of planned capital investments on O&M costs are also provided, the investment drivers are reviewed, and the system capability assessment for REGs is identified.

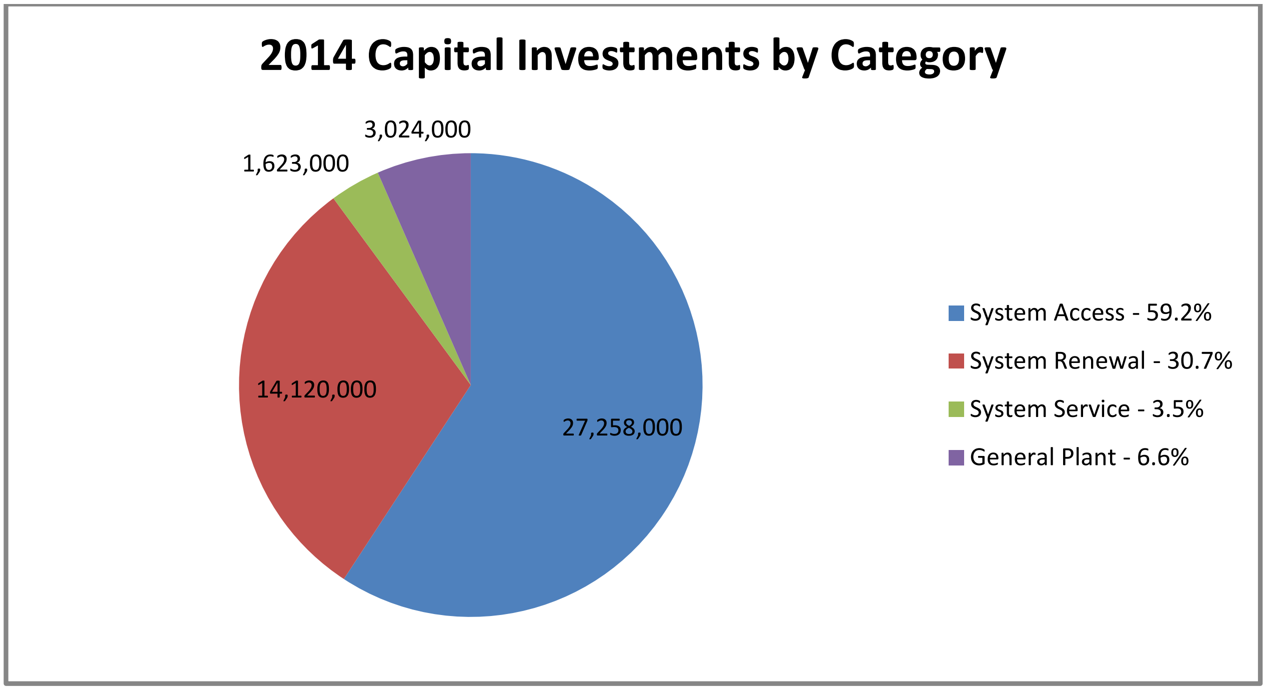
Allocation by Category

Capital investments have been allocated to one of the four investment categories as required by the Ontario Energy Board's Filing Requirements for Electricity Transmission and Distribution Applications Chapter 5, entitled Consolidated Distribution System Plan Filing Requirements ("Chapter 5") dated March 28th 2013. They are:

- System Access
- System Renewal
- System Service
- General Plant

Chart 1 provides Veridian's planned 2014 capital investments by category.

Chart 1 – 2014 Capital Investments by Category



Expenditures by category over the historic period are found in Exhibit 2, Tab 3, Schedule 10, Attachment 1, Appendix 2-AB.

<u>2014 Capital Projects by Category Greater than $260,000 Materiality</u>

System Access projects total $27.3M and represent 59.2% of the capital spend within the capital expenditure plan. Capital projects in this category above materiality are:

- New Residential Developments (Growth) - $5,198,000
- Highway #407 & Brock Road - $3,908,000
- Highway #401 & Highway 407 Link at Lakeridge Road - $2,583,000
- Dundas Street (Build Belleville) - $2,200,000

- Front Street (Build Belleville) - $1,979,000
- Highway #407 at Westney Road - $1,805,000
- Transformers for New General Services (Growth) - $1,400,000
- Taunton Road, Church Street to Brock Road (Seaton Community Feeders) - $1,331,000
- Highway #2 at Liverpool Road (BRT) - $1,184,000
- Highway #2 at Fairport Road (BRT) - $1,067,000
- Rossland Road, Church Street to Southcott Road (Road Relocation) - $735,000
- Index Energy, Ajax (REG) - $700,000
- Customer Requested Pole Relocation - $625,000
- Long Term Load Transfer Eliminations - $600,000
- Highway #407 at 5th Concession - $460,000
- Retail Meters - $455,000
- Port Hope Croft Street - $357,000
- Airport Parkway West Overhead Extension - $307,000

System Renewal projects total $14.1M and represent 30.7% of the capital spend within the capital expenditure plan. These projects are divided into two large groups; reactive sustainment, and proactive sustainment.

The reactive sustainment projects in this category are:

- Ajax District - $935,000
- Clarington District - $715,000
- Belleville District - $710,000
- Brock District - $340,000

The proactive sustainment projects in this category are based on the major asset categories assessed in the ACA with Veridian staff adjusted results:

- Substation transformers - $4,047,000
- Wood poles - $2,041,000
- Underground cables - $1,000,000
- Pad mounted switch gear - $900,000
- Pad mounted transformers - $800,000
- Pole mounted transformers - $736,000
- Overhead line switches - $706,000
- Substation breakers and reclosers - $600,000

System Service projects total $1.6M and represent 3.5% of the capital spend within the capital expenditure plan. Capital projects in this category above materiality are:

- Port of Newcastle – 13.8kV Loop Feed - $444,000
- First Street Voltage Conversion, Gravenhurst - $432,000
- Ground Grid Upgrades & Oil Containment - $300,000

General Plant projects total $3.0M and represent 6.6% of the capital spend within the capital expenditure plan. Capital projects in this category above materiality are:

- Large Bucket Truck - $400,000
- Mobile Computing Integration - $300,000

The above projects for the 2014 test year are found in Veridian's capital expenditure plan.

Impacts on O&M Costs

The completion of Veridian's Asset Condition Assessment (ACA) identified some data gaps in the parameters for each of the asset categories (ACA inputs), that when updated, will improve the quality of the results (ACA outputs). These data gaps directly tie in with proposed capital investments for developing the remedies to the data gaps, as well as in O&M costs to complete the data gathering to fill the data gaps. Specific O&M funded activities are testing programs for wood poles and for underground primary cables. The primary output of the wood pole testing program is an expert assessment of pole strength and a ranked listing of poles recommended for replacement. Other data is gathered during the testing including all relevant pole data such as species of wood and date of manufacture and identification of any concerns from a visual inspection of the pole and pole mounted equipment performed by the contractor while at the pole. All data gathered will be integrated into the GIS. Contractor performed testing of underground cables will be a new program for Veridian and will utilize a test method known as 'tan delta' or dissipation factor testing. Through this testing Veridian will be able to quantify cable insulation condition and enable improved prioritization of cable refurbishment and replacement programs. Veridian will be accelerating its testing program for 25,000 wood poles over the forecast period of 2014–2016 at a rate of 8,300 per year, and approximately 23 km of underground primary cable will be tested on an ongoing annual basis. Table 1 provides the operating costs per year over the forecast period. The costs associated with pole testing over the 2014 through 2018 period have been amortized over 5 years for inclusion in 2014 revenue requirement at $150 thousand per year. The ACA as it applies to Veridian's asset management process can be found in Exhibit 2, Tab 3, Schedule 4. The complete ACA study is found as Exhibit 2, Tab 3, Schedule 6, Attachment 1.

Table 1 Summary of Operating Costs for Testing Programs (K $)

ITEM #	ASSET	2014	2015	2016	2017	2018
1	Poles	$250	$250	$250	$0	$0
2	Underground Cables	$160	$160	$160	$160	$160
	TOTAL	**$410**	**$410**	**$410**	**$160**	**$160**

For the test year, the results of the ACA were taken into consideration when Veridian selected and prioritized its candidate capital projects to be submitted for approval in the annual budgeting process. It should be noted that the recommendations provided in the ACA relating to the number and timing of asset replacements were based on analysis of limited, currently available data. Veridian staff assessed the recommendations and in conjunction applied judgement to spread the replacements over a longer period of time to balance and smooth budget and resources impacts. Therefore in some cases, the annual planned proactive replacement numbers that have been included in Veridian's 2014 capital expenditure plan will vary from those recommended by the ACA results. As the ACA results continue to be refined using information from Veridian's ongoing proactive inspection and maintenance programs, priorities and scheduling will be adjusted to obtain optimal results.

The consideration for cost savings is inherent in Veridian's philosophy in its planning and capital plan execution and their impacts on O&M costs. Veridian has identified the following sources as having potential O&M cost savings. A number of these sources are also expected to positively impact customer satisfaction through improvements in system reliability performance metrics over time through reduced unplanned outages and reduced restoration times.

Asset Management Plan (AMP) Development

The development of the AMP will result in targeting specific assets to be replaced based on complete asset condition data. These assets will be those which will be identified as most likely to fail. Cost savings will result over time from reduced reactive after hours trouble call response which is completed at overtime labour rates as the proactive planned asset replacement would generally occur through the day during normal working hours and at regular labour rates.

Proactive Planned Sustainment Programs

The proactive planned sustainment programs will result in cost savings over time from the reduction of reactive after hours trouble call response which is completed at overtime labour rates as the proactive planned replacement would generally occur through the day during normal working hours and at regular labour rates.

Capital Project Engineering/GIS Integration

An improved integration between the Engineering and the Operations Information Systems (OIS) departments will result in labour cost savings in both departments by minimizing the time and effort currently expended in multiple manipulations of engineering design drawings.

Distribution Automation (Smart Grid)

Continuing investments in the Distribution Automation (DA) will result in cost savings from the reduction in regular and overtime labour costs during planned operations, such as typical day-to-day switching, and during unplanned power restoration operations. DA equipment remotely operated from Veridian's System Control Centre (SCC) eliminates the requirement for line staff to travel to the equipment's physical location to switch or operate the equipment manually. Cost savings through a more efficient use of resources result for both the operating and capital aspects.

Mobile Computing/Data Acquisition (GIS Programming Enhancements)

Veridian is continuing to expand the use of its GIS across the organization through the continued roll-out of mobile computing and web-based products. The expected cost savings will result from a reduction of labour costs associated with moving away from the current paper-based systems and towards this mobile workforce management type of system.

Standards Department - Asset Failures

All asset failures are analyzed to determine the root cause of failure. Any trending on any particular asset type, manufacturer, style, or age, etc., is recognized with appropriate actions identified. Cost savings will result over time from the reduction of reactive after hours trouble call response which is completed at overtime labour rates as the proactive planned replacement would generally occur through the day during normal working hours and at regular labour rates.

Standards Department – Design Standards & Specifications

Veridian's Standards Department will continue to develop its engineering design standards and specifications in an ongoing effort to drive for cost savings by "standardizing" the design and construction of Veridian's capital projects. With Veridian's diverse service areas, significant legacy assets, and its capital expenditure plan commitments, the requirement for standardization is key to reducing the labour costs in the engineering design process, reducing the asset components required to be maintained in inventory, and completing construction in a consistent and repeatable manner. Once standardization is fully in place, the next step will be to optimize the execution and delivery of the engineering and construction tasks not only for capital projects but for O&M activities as well to further drive cost savings, process improvements, and overall efficiency.

Please refer to Exhibit 2, Tab 3, Schedule 1, for further details on potential cost savings.

Drivers of Investments

It is expected that the operational and service requirements driving Veridian's capital expenditures, and found within its Distribution System Plan (DSP), will generally remain consistent through the 2014 to 2018 planning window. The projected expenditures for the test year, and going forward, include the typical spending needs of a geographically distributed electricity distribution utility serving a growing customer base and with a diverse collection of physical assets. Further, they include the ongoing planned capital sustainment investments required to replace the aging assets found in Veridian's distribution system.

There are a number of key elements that affect Veridian's DSP for the capital investment plans for the test and future years. These are:

- Planned distribution asset sustainment programs;
- Seaton Community in north Pickering;
- Seaton Transformer Station (TS) in north Pickering;
- Growth and development; and
- Provincial, regional, and municipal infrastructure improvements (road relocations).

<u>Planned distribution asset sustainment programs (2014 +)</u>

Veridian will continue to manage a reactive program of unplanned sustainment to replace the assets that fail in-service or those that need to be replaced due to poor condition, before they fail or if they pose a safety risk to the public or workers. Veridian will also be implementing an ongoing proactive program of planned sustainment to replace an identified quantity of various categories of distribution assets before they fail. Veridian will continue to invest in replacing or refurbishing its assets in order that they continue to meet all company and customer performance expectations.

Seaton Community (2015–2021)

Development in the Seaton community located in north Pickering is currently underway and is expected to be a significant driver of development. Municipal growth projections indicate that 1700 residential building lots will require connection each year, starting in 2015 and continuing for a number of years. Based on this new load projection, additional capacity and distribution feeder infrastructure will be required by 2018 if actual connection quantities match the projections. The new feeder infrastructure is included in the 2014 capital expenditure plan as well as in subsequent year plans, to continue from their present endpoint in Ajax and extend into the Seaton Community in Pickering. Once completed, these feeders will bring available capacity from the existing Whitby TS to fully utilize that TS asset as well as satisfy capacity needs until the Seaton TS described below enters service.

Seaton TS (2013–2018)

The additional requirement for capacity for the Seaton Community is the main driver behind the Seaton TS project, which is targeted to be in-service for 2018. The Seaton TS project itself is projected to be a capital investment of approximately $21M in 2018. The TS project has a multi-year timeline from concept through to in-service and this project is currently in progress. Veridian is currently completing its build or buy business case for the TS. New feeder construction projects extending into the Seaton community are included in the capital investment plan for 2014 through 2018.

Growth and Development

Growth occurs at different rates between Veridian's five operating districts. It is expected that the Ajax, Belleville and Clarington districts will continue to see fast growth as it relates to the other districts, as expansion pushes out and further develops out into the GTA. Slow to little growth is expected in the Brock and Gravenhurst districts. The Seaton community as described above is the single most significant growth area expected to develop within the planning window. Veridian's system planning staff has already identified a long term servicing plan for the Seaton Community and for the development lands expected on either side of Highway #407.

Road Relocations (2013–2015)

The Ministry of Transportation's Highway #407 extension from its current end point in Pickering through to the Ajax district's eastern service boundary is currently underway with expectations that it will be completed between 2013 and 2015. There is significant linkage between the extension of Highway #407, the Seaton Community, area growth and development, and the Seaton TS. The first three of these factors will not only be drivers for each other, but will drive the necessity for the fourth. The Highway #407 extension involves significant asset removal, asset relocations, and new asset construction entirely with multiple millions in gross capital investments as well as a significant commitment of resources for this non-discretionary project, of which there are 13 sub-projects.

The Region of Durham's Highway #2 Bus Rapid Transit (BRT) projects are encompassed under a regional transit priority initiative. The widening of Highway #2 through Ajax and Pickering from 4 lanes to 6 lanes will affect several major intersections along its route which will require significant relocations of Veridian's existing overhead assets. The Region's target for completion is March 2016.

Build Belleville is an ongoing municipal infrastructure renewal program targeting the City of Belleville's roads and bridges, water and sewage assets. The various municipal projects included are at preliminary stages in the design process and the associated road works will require significant relocations of Veridian's existing overhead assets.

Projects associated with the above and their descriptions for the 2014 test year are found in Veridian's capital expenditure plan.

Please refer to Exhibit 2, Tab 3, Schedule 1, Exhibit 2, Tab 3, Schedule 5 and Exhibit 2, Tab 3, Schedule 8 for further details on capital investment drivers.

Veridian has identified performance measures relating to its capital investment plan, as detailed in Exhibit 2, Tab 3, Schedule 3. The relevance of each of these measures to each of the four investment categories is presented in the following Table 2:

Table 2 – Performance Measures Relevant to Capital Investment Category

Performance Measures	Capital Investment Categories			
	System Access	System Renewal	System Service	General Plant
Reliability		X		
Planned Inspection and Maintenance Programs		X		
Substation Loading/Capacity	X		X	
Standards Department – Asset Failure		X		
Planned Capital Expenditure Completion Rate	X	X	X	X
Safety	X	X	X	X
Operations and Maintenance Costs	X	X	X	X
Customer Bill Impacts	X	X	X	X

System Capacity Assessment for REGs

Veridian has completed an extensive review of its distribution system for the purpose of determining the need for capital investments to accommodate the connection of REG projects. Veridian has determined, based on its experience regarding the number of applications received to-date, that only one distribution system expansion is required to accommodate the connection of REG projects during the test year of 2014. The particular project is for an application for a 25.012 MW generation facility for Index Energy in Ajax, ON, which is scheduled for connection during 2014. It is important to note that there are system constraints to the connection of REG projects within Veridian's service territory; however those constraints are located at Hydro One owned transformer stations. Please refer to Exhibit 2, Tab 3, Schedule 9, for further details.

Material Investments - Justification

Veridian's capital projects for 2013 and 2014 have been categorized per the Board's Investment Categories as listed in the filing requirements for Chapter 5. All material project descriptions are provided in Exhibit 2, Tab 3, Schedules 13-17 which are listed in the following order: System Access, System Renewal, System Service, General Plant-Fleet and General Plant- Information Technologies. There are no material projects forecast for General Plant- Facilities for either 2013 or 2014. The explanatory project narratives have been developed to enable the Board's assessment of these plans by providing the information requested concerning general information, evaluation criteria used, as well as the category specific information requirements.

Attachment 1 of 2

Table of Material Investments 2013 and 2014 by Category

Category	Project Name	Gross Expenditure ($000's)	Net of Contributions ($000's)	In Service Date
System Access *(Exhibit 2, Tab 3, Schedule 14)*				
2013				
	Brock St West Joint Feeder Extension-Uxbridge	$ 600	$ 430	Dec-13
	College Street Extension- Belleville	$ 294	$ 144	Dec-13
	Highway 407 Extension - Various Road Relocations	$ 5,288	$ 1,451	Dec-13
	Highway #2 Road Widening - Bus Rapid Transit-Phases 1 & 2	$ 1,024	$ 818	Dec-13
	LTLT Eliminations - Various Locations	$ 650	$ 650	Dec-13
	New GS Services	$ 1,166	$ -	Dec-13
	New Residential Services	$ 4,018	$ 2,278	Dec-13
	Line Relocation, Orono Creek, Clarington	$ 258	$ 39	Dec-13
	Retail Meters	$ 479	$ 479	Dec-13
	Rossland Road Relocation (Clearside X Southcott), Ajax	$ 385	$ 289	Dec-13
	Westney Road Relocation (Magill X Telford), Ajax	$ 1,475	$ 1,038	Oct-13
	Southeast Sewer Collector (SEC) Project	$ 350	$ -	Dec-13
2014				
	Dundas Street (Coleman to Baybridge)	$ 2,200	$ 299	Dec-14
	Feeder Relocation, Front Street (Dundas X Pinnacle), Belleville	$ 1,979	$ 279	Dec-14
	Highway 407 Extension - Various Road Relocations	$ 8,758	$ 2,361	Dec-14
	Highway #2 Road Widening - Bus Rapid Transit-Phases 1 & 2	$ 2,251	$ 1,832	Dec-14
	Rossland Road (Southcott to Church)	$ 736	$ 509	May-14
	LTLT Eliminations - Various Locations	$ 600	$ 600	Dec-14
	New GS Services	$ 1,400	$ -	Dec-14
	New REG Connection, Ajax	$ 700	$ 700	Mar-14
	New Residential Services	$ 5,198	$ 3,370	Dec-14
	O/H Line Extension - Airport Parkway West, Belleville	$ 307	$ 307	Sep-14
	Line Relocation, Orono Creek, Clarington	$ 85	$ 53	Oct-14
	Relocation of 44 kV Pole Line, Port Hope	$ 625	$ -	Dec-14
	Retail Meters	$ 455	$ 455	Dec-14
	Three 27.6 kV circuits-Taunton Road (Church to Brock)	$ 1,332	$ 1,332	May-14
System Renewal *(Exhibit 2, Tab 3, Schedule 15)*				
2013				
	Reactive Pole Replacements	$ 752	$ 752	Dec-13
	Reactive Transformer and Component Replacements	$ 900	$ 900	Dec-13
	South Ajax Cable Replacement - Finley Avenue	$ 1,875	$ 1,875	Dec-13
	Storm Damage Rebuild - Gravenhurst July 2013	$ 799	$ 799	Aug-13
2014				
	New Feeder - Croft Street, Port Hope	$ 357	$ 357	Apr-14
	Overhead Line Switch Replacement Program, various	$ 706	$ 706	Dec-14
	Padmount Transformers Replacement Program, various	$ 800	$ 800	Dec-14
	Padmounted Switchgear Replacement program, various locations	$ 900	$ 900	Dec-14
	Polemount Transformer Replacement Program, various	$ 736	$ 736	Dec-14
	Primary Cable Rehabilitation Program, various locations	$ 1,000	$ 1,000	Dec-14
	Reactive Pole Replacements	$ 752	$ 752	Dec-14
	Reactive Transformer and Component Replacements	$ 900	$ 900	Dec-14
	Substation Breakers Replacement, Toronto Substation	$ 600	$ 600	Nov-14
	Substations Transformer Replacement, Greenwood Substation	$ 713	$ 713	Oct-14
	Substation Transformer Replacement and Component Upgrades- Fairport SS	$ 2,435	$ 2,435	Nov-14
	Substation Transformer Spare Replenishment	$ 900	$ 900	Jul-14
	Wood Pole Replacement Program, various locations	$ 2,042	$ 2,042	Dec-14
System Service *(Exhibit 2, Tab 3, Schedule 16)*				
2013				
	Pickering Beach Substation Upgrade, Ajax	$ 2,120	$ 2,120	Jun-13
	SCADA System Replacement / Upgrade	$ 601	$ 601	Dec-13
	Voltage Conversion - 4.16kV First Street (First X James), Gravenhurst	$ 450	$ 450	Dec-13
	Wilmot Substation Upgrade, Newcastle	$ 1,900	$ 1,900	Dec-13
2014				
	New Feeder-13.8 kV Loop Feed, Port of Newcastle, Newcastle	$ 444	$ 444	Oct-14
	Substation Oil Containment	$ 300	$ 300	Oct-14
	Voltage Conversion - 4.16kV First Street (First X James), Gravenhurst	$ 432	$ 432	Dec-14
General Plant *(Exhibit 2, Tab 3, Schedule 17)*				
Fleet				
2014				
	Vehicles (1 large bucket truck)	$ 400	$ 400	Dec-14
Information Technology				
2013				
	GIS Computer Software	$ 140	$ 140	Dec-13

Category	Project Name	Gross Expenditure ($000's)	Net of Contributions ($000's)	In Service Date
	High Availability Data Site	$ 350	$ 350	Dec-13
	Mobile Computing	$ 400	$ 400	Dec-13
	Unified Messaging - Phone System Replacement, Phases 1 and 2	$ 451	$ 451	Nov-13
2014				
	Business Continuity/Disaster Recovery Site	$ 200	$ 200	Oct-14
	GIS Computer Software	$ 150	$ 150	Dec-14
	Mobile Computing	$ 300	$ 300	Dec-14
	Unified Messaging - Phone System Replacement, Phases 1 and 2	$ 60	$ 60	Jun-14

Attachment 2 of 2

Comparison of 2014 Projects to Prior Projects

Comparison of 2014 Projects to Prior Projects

At page 20 of the Chapter 5 Consolidated Distribution System Plan Filing Requirements, the Board directs that utilities should provide "[if not evident from Table 2,] comparative information on expenditures for equivalent projects/activities over the historical period, where available" for material projects in the test year.

Table 2 is the Capital Expenditure Summary, which presents information by category over the historical plan period and the forecast period. Although Veridian has not submitted a Distribution System Plan previously, it has attempted to re-cast historical project and expenditure records to provide an indication of how those expenditures might be classified according to the current system.

To supplement the information set out in Table 2, Veridian has constructed Table 1 to indicate for material test year projects any prior period projects which are reasonably "equivalent", in the Board's terminology. Although no two projects are strictly equivalent, any test year project may be more or less comparable to a previous project depending on a number of project-specific factors. Generally, projects involving repetitive, similar activities year over year are more comparable; projects that are highly location- or equipment-specific are less comparable, and may even be unprecedented.

Furthermore, while projects may be categorically similar or the same, the specific expenditures on different projects may differ substantially due to differences in scope or initial conditions. For example, overhead plant re-location projects are categorically the same at high levels of classification, but may differ significantly in total cost and/or unit cost due to differences in scope, complexity, requirements for temporary construction, and other factors.

To assist the Board, Table 1 presents Veridian's view, for each test year project, on what prior year projects could be considered comparable, as well as the degree or kind of comparability. Highly comparable projects (High Similarity rating) are similar in kind as well as in scope and circumstances. Comparable projects (Medium Similarity rating) are similar in kind and may have similar unit costs, but may differ in scope leading to differences in total cost. Somewhat comparable projects (Low Similarity rating) are categorically the same at high levels of classification (e.g., plant relocation), but may differ noticeably in other ways, such as degree of complexity, so that both unit and total costs differ markedly. Finally, projects that are highly specialized and/or tailored to unique circumstances in a given setting may have no meaningful comparators (Not Similar rating).

Table 1- 2014 Material Projects Comparator Chart

Category	Project Name	Suggested Comparison Project	Similarity Rating (Low; Medium; High; Not Similar)
System Access	Front Street (Dundas X Pinacle), Belleville	None	Not Similar
System Access	Hwy 2 - Road Widening - BRT Phases 1 and 2	2012- Brock Road Relocation- Bayly to Kingston Rd	High
System Access	Hwy 407 Extension - Various Road Relocation Projects	2013-Bayly Street-Shoal Point to Lakeridge	Medium
System Access	Line Rebuild - Rossland Road (Southcott X Church), Ajax	2013-Bayly Street-Shoal Point to Lakeridge	High
System Access	LTLT Eliminations	None	Not Similar
System Access	New 27.6kV Circuits for Seaton Development - Taunton (Church X Brock), Ajax	2010 Hwy #7 Pole Relocation -Brock to Lakeridge	Medium
System Access	New GS Services	2010-2013 New GS Services	High
System Access	New REG Connection, Ajax	2013-Bayly Street-Shoal Point to Lakeridge	Medium
System Access	New Residential Services	2010-2013 New Residential Services	High
System Access	O/H Line Extension - Airport Parkway West, Belleville	2013-Bayly Street-Shoal Point to Lakeridge	Medium
System Access	Retail Metering - New Services	2010-2013 Retail Metering- New Services	High
System Access	U/G Relocation - Dundas (Coleman x Baybridge), Belleville	2013 South Ajax Cable Replacement Program	Medium
System Renewal	O/H Line Switch Replacement Program, various locations	None- new program	Not Similar
System Renewal	New Feeder - Croft Street, Port Hope	2013-Bayly Street-Shoal Point to Lakeridge	Medium
System Renewal	Padmount Transformers Replacement Program, various locations	None- new program	Not Similar
System Renewal	Padmount Switchgear Replacment Program, various locations	None- new program	Not Similar
System Renewal	Polemount Transformers Replacement Program, various locations	None- new program	Not Similar
System Renewal	Port Hope - Relocation 44kV Pole Line	2013-Bayly Street-Shoal Point to Lakeridge	Medium
System Renewal	Primary Cable Rehabilitation Program, various locations	None- new program	Not Similar
System Renewal	Reactive Pole Replacements	2010-2013 Reactive Pole Replacements	High
System Renewal	Reactive Transformer and Component Replacements	2010-2013 Reactive Transformer and Comp Repl.	High
System Renewal	Substation Breakers Replacements, various locations	None- new program	Not Similar
System Renewal	Substation Transformer Replacement - Fairport SS, Pickering	None- new program	Not Similar
System Renewal	Substation Transformer Replacements, various locations	None- new program	Not Similar
System Renewal	Substation Transformer Spare Replenishment, various locations	None- new program	Not Similar
System Renewal	Wood Pole Replacement Program, various locations	2010-2013 Reactive Pole Replacements	Medium
System Service	13.8kV Loop Feed, Port of Newcastle, Clarington	None- no similar 3rd party attacher project	Not Similar
System Service	Substation Oil Containment	2010 Substation Oil Containment	Medium
System Service	Voltage Conversion - 4.16kV First Street (First X James), Gravenhurst	None- no similar voltage conversion project	Not Similar
General Plant	Vehicle- Large, 1 Bucket Truck	2012- Vehicle- Large, 1 Bucket Truck	Medium
General Plant	IT- Mobile Computing	2013- Mobile Computing	High

Material Investments - 2013 and 2014 - System Access Category

Name of Project	Brock St West Joint Feeder Extension- Phases 1 to 3 Uxbridge
Project Classification	System Access
Start Date	November 2012
In Service Date	December 2013
Capital Expenditure	\$0.367 million gross in 2012 – Phase 1 \$0.600 million gross in 2013 – Phase 2 & 3 \$0.967 million gross total (0.797 million net)

Refer to Historical Project Descriptions found in Exhibit 2, Tab 2, Schedule 2 of this Rate Application.

Project Cost Summary:	**\$0.967 million gross**
Labour & Fleet	\$0.483 million
Material	\$0.306 million
Contractor/Other	\$0.178 million

Name of Project	College Street Extension
Project Classification	System Access
Start Date	November 2013
In Service Date	December 2013
Capital Expenditure	$0.294 million gross, $0.144 million net

Overview

This system access project will provide service to a new pumping station in the City of Belleville and the area immediately adjacent to it. The pumping station will be sited on newly developed land to be served by an extension of the existing College Street. Veridian's distribution system currently ends approximately 350 metres before the location of the pumping station.

In order to provide this service, Veridian will rebuild a short portion of its existing distribution system over six pole spans and extend it to the unserved area of the College Street extension. The existing pole line carries one 13.8kV circuit and one 44kV circuit. The 44kV circuit will be moved to the new poles but not extended at this time. The 13.8kV circuit will provide service to the pumping station and the immediately adjacent area.

Project Description

The existing 13.8kV, 3-phase circuit will be extended by installing six replacement poles and nine new poles, carrying 556 KCMIL conductor, together with associated equipment including one guy pole. The pole line will have provision for an extension of the 44kV circuit in the future to avoid the costs of having to rebuild for that purpose.

The pole line will also intersect an existing Hydro One 44kV pole line and will require rework on three of those poles.

A capital contribution in the amount of $150,000 is expected from the City of Belleville in connection with this project.

Project Cost Summary:	**$0.294 million gross**
Labour & Fleet	$0.180 million
Material	$0.100 million
Contractor/Other	$0.014 million

Name of Project	Highway 407 Extension – Various Road Relocation Projects
Project Classification	System Access
Start Date	October 2013
In Service Date	December 2014
Capital Expenditure	$5.288 million gross in 2013, $1.451 million Net $8.758 million gross in 2014, $2.361 million Net $14.046 million gross Total, $3.812 million Net

Overview

The Ministry of Transportation ("MTO") is extending Highway 407 from Brock Road in Pickering to Harmony Road in Oshawa. A link road known as the West Durham Link from Highway 407 to Highway 401, just east of Lakeridge Road, is also being constructed. This link road affects the bridge over Highway 401 at Lakeridge Road. In addition, the intersection of Highway 407 at Brock Road is moving further to the east, and Brock Road is being re-aligned to this new location.

Veridian's assets are affected at a number of locations due to this road construction. This system access project is composed of 13 parts, all of which are related to the easterly expansion of Highway 407 and are being undertaken by Veridian at the request of the Ministry of Transportation. Nine of the parts are to be undertaken in 2013 with the remaining four to be completed in 2014, contingent upon the finalization of designs, specifications and financial arrangements with the MTO. Due to the considerable size and complexity of this road construction project and the numerous stakeholders involved, the actual schedule of work continues to evolve and change. The schedule noted above has been based on the best information available in August 2013. Veridian will continue to work with the MTO satisfy their requirements.

The thirteen parts, or 'scopes', vary in character but are all required by the Highway 407 expansion and other associated road construction. Depending on the specific circumstances at a given location, the scope could involve permanent relocation or temporary relocation followed by permanent relocation, new construction, or a change from existing overhead to new underground. The details pertaining to each part are set out below.

The gross capital expenditures associated with the project are large but proportionate to the work being done. However, while capital contributions from the MTO remain to be finalized, Veridian estimates on the basis of reasonably advanced designs and discussions that approximately 73% of the gross cost will be covered by capital contributions. The capital contribution for each scope depends on the circumstances attaching to that work, and specifically on factors such as whether temporary relocation is required, and whether new construction is involved. Please also refer to Exhibit 2, Tab 3, Schedule 8, Attachment 2, Explanation of Veridian Contribution Policy for a general discussion of capital contributions.

Because the Highway 407 extension is a large, 'one-time' undertaking for Veridian, and requires substantial resources to complete the design of the electrical work, Veridian has contracted out this element of the work to avoid excessive overtime costs that would be incurred if internal staff were employed for this purpose as well as not being able to complete the design on other Veridian projects due to their focus on this project. Similarly, to the extent that construction requirements exceed the capacity of Veridian's construction crews, Veridian will engage contractors to complete construction work as necessary.

Project Description

2013 Projects

Scope		Gross Cost $(Millions)	Net Cost $(Millions)
1	Lakeridge Road (Highway 2 to Bayly Street)	$0.292	0.0
2	Highway 407 at Highway 7	$2.479	0.601
3	Highway 407 at Brock Road (Part 1)	$1.351	0.629
4	Highway 407 & Sideline 14	$0.130	0.071
5	Highway 407 & Westney Road (Part 1)	$0.750	0.0
6	Highway 407 & Salem Road	$0.180	0.096
7	Highway 407 & Sideline 4	$0.008	0.004
8	Highway 407 & Kinsale Road	$0.013	0.007
9	Highway 407 & Lakeridge Road North	$0.085	0.043
	Total 2013	$5.288	1.451

Please also refer to Figure 1 on the following page for a map of scope locations.

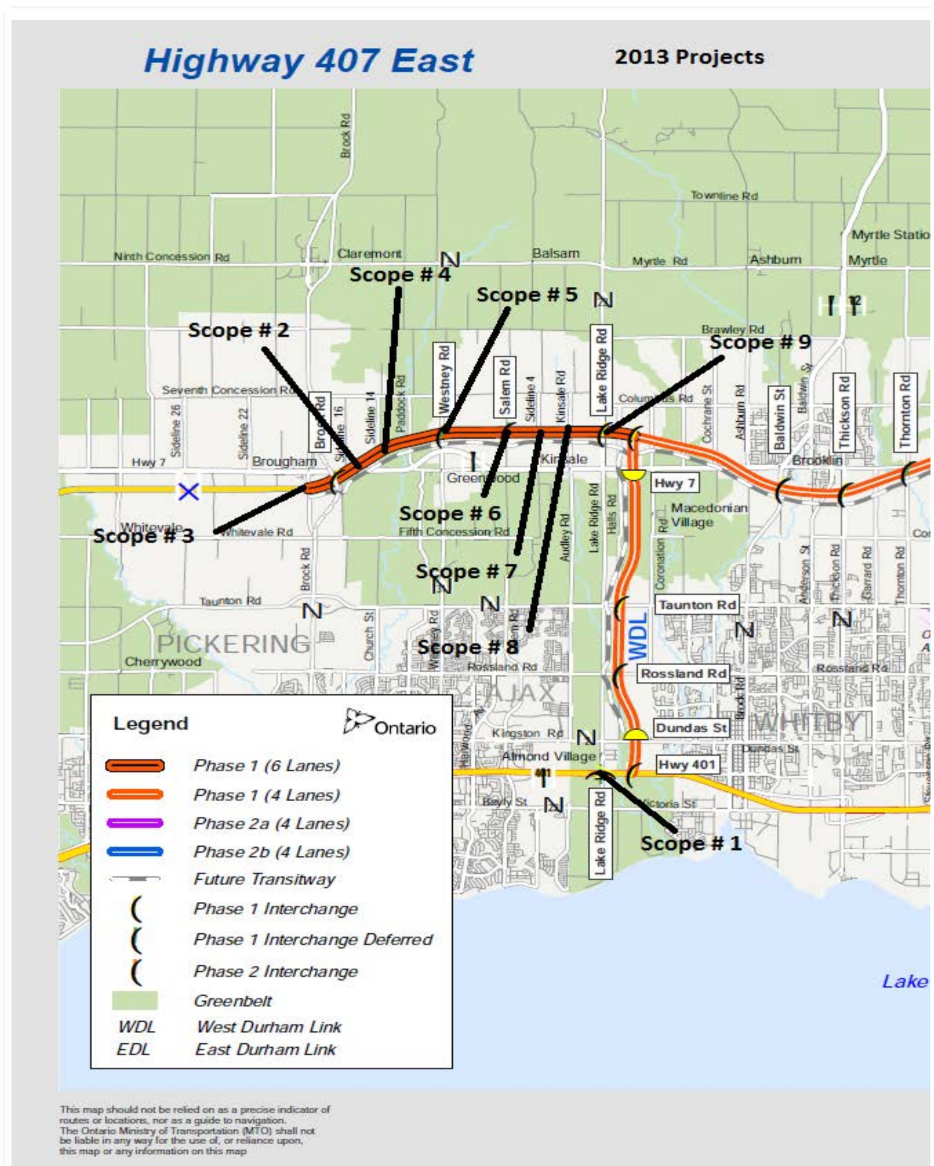
Scope 1: Lakeridge Road (Between Highway 2 and Bayly Street)

A significant component of the easterly extension of Highway 407 will be the construction of the West Durham Link, a limited access highway connecting Highway 407 and Highway 401. To construct the West Durham Link, Lakeridge Road will be moved. As a result, the MTO has requested a temporary relocation of the existing pole line at this location to permit the reconstruction of the existing bridge over Highway 401. Veridian will be installing 8 poles and removing 11 poles.

Because this is a temporary relocation done to enable MTO construction work, the cost is totally borne by the MTO.

Please also refer to Scope 13, which pertains to the removal of this temporary relocation.

Figure 1: Locations of 2013 Work



Scope 2: Highway 407 at Highway 7

The existing Highway 7 needs to be relocated at this section of the Highway 407 extension project, which in turn requires Veridian to rebuild the existing pole line on Highway 7 at a new location. This requires the installation of 34 wood poles and the removal of 26 wood poles, over a total project length of 1.4 km.

It is also necessary for part of this infrastructure to be placed underground, in order to maintain electrical clearances away from workers and machinery during construction. Approximately 0.4 km of three phase underground circuit is required for this reason. Undergrounding this equipment avoids the need for a temporary relocation that would later have to be reversed. Net costs for Veridian reflect that there are improvements to the Veridian system from the installation of additional ducts in the section of undergrounding. This incremental cost increase will minimize future servicing costs as the anticipated load materializes.

Scope 3: Highway 407 at Brock Road (Part 1)

At present Veridian has an overhead feeder that crosses Highway 407 at Brock Road. Due to the widening of Highway 407 at this location, and the associated realignment of Brock Road, it is necessary for Veridian to reconfigure the feeder line. To accomplish this within the timelines of Highway 407 reconstruction, it is necessary to underground the section of the feeder running across the widened highway, since the steel poles necessary to run the feeder overhead could not be designed and constructed in time. Veridian notes that steel poles are custom engineered and manufactured and require long lead times for production.

The underground section is approximately 0.5 km in length. The overhead pole line section also needs to be moved and reconfigured, and requires 8 wood poles to be installed and 10 wood poles to be removed. Net costs for Veridian reflect that there are improvements to the Veridian system from the installation of additional ducts in the section of undergrounding. This incremental cost increase will minimize future servicing costs as the anticipated load materializes.

Please also refer to Scope 11 for a description of work to be done in 2014 at this location.

Scope 4: Highway 407 at Sideline 14

In several instances including this one, the extension of Highway 407 has necessitated the expropriation of properties along its route, and as a result, has removed the requirement for Veridian to serve customers whose properties have been expropriated. Veridian's assets that are in the path of the construction also have to be removed. For these reasons, this section of the project requires the installation of 5 wood poles to continue service to remaining customers and the removal of 14 wood poles.

Scope 5: Highway 407 at Westney Road (Part 1)

At this location, construction of Highway 407 and the associated interchange requires that Veridian's existing pole line be temporarily relocated to facilitate construction and maintain safe clearances from overhead electrical equipment, while maintaining service to existing customers. This in turn involves installing 14 wood poles and removing 11 wood poles.

Because this is a temporary relocation done to enable MTO construction work, the cost is totally borne by the MTO.

Please also see Scope 12, which involves the reversal of this work.

Scope 6: Highway 407 at Salem Road

The background and rationale for this scope of work is the same as for Scope 4. This section of the project involves the installation of 1 wood pole and the removal of 14 wood poles.

Scope 7: Highway 407 at Sideline 4

The background and rationale for this scope of work is the same as for Scope 4. This section of the project requires the installation of 1 wood pole, and the removal of 1 wood pole.

Scope 8: Highway 407 at Kinsale Road

The background and rationale for this scope of work is the same as for Scope 4. This section of the project requires the installation of 1 wood pole, and the removal of 4 wood poles.

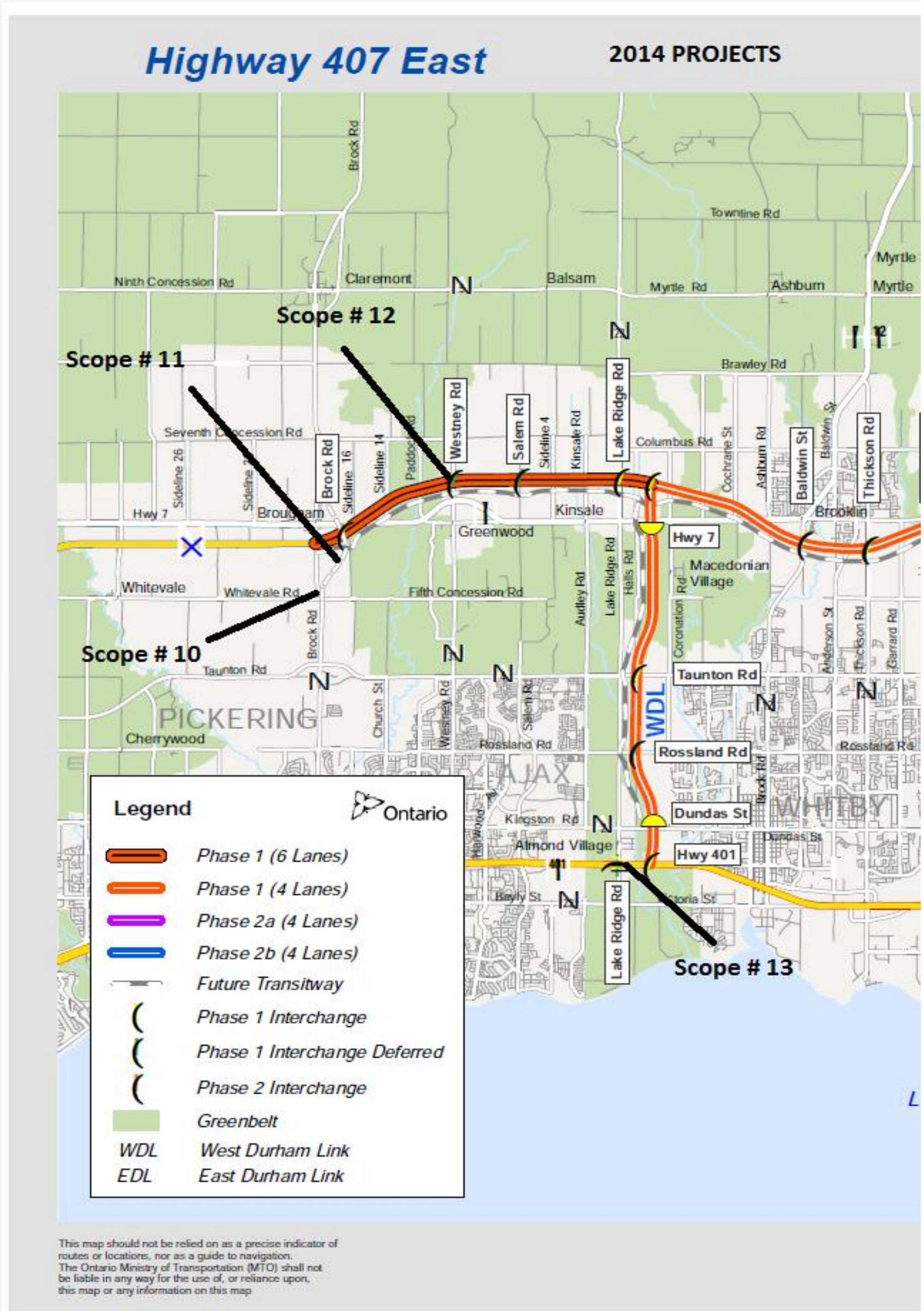
Scope 9: Highway 407 at Lakeridge Road North

The background and rationale for this scope of work is the same as for Scope 4. This section of the project requires the installation of 1 wood pole, and the removal of 11 wood poles.

2014 Projects

Scope		Gross Cost $(Millions)	Net Cost $(Millions)
10	Highway 407 - Brock Road at 5th Concession	$0.461	0.085
11	Highway 407 at Brock Road (Part 2)	$3.908	0.050
12	Highway 407 (Brock to Lakeridge) at Westney Road (Part 2)	$1.806	0.766
13	Highway 401 & Highway 407 Link at Lakeridge Road	$2.583	1.460
	Total 2014	$8.758	2.361

1 Figure 2: Locations of 2014 Work



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Scope 10: Highway 407 – Brock Road at the 5th Concession Road

In connection with the construction of Highway 407, Brock Road is being re-aligned north of the 5th Concession Road. To accommodate this road realignment, this section of the project requires the installation of 20 wood poles to serve new load associated with highway and the removal of 13 wood poles which conflict with the new location of roadway.

Scope 11: Highway 407 and Brock Road (Part 2)

This section of the work is required by the re-routing of Brock Road to intersect with Highway 407 at a new location to the east of the existing intersection. This portion of the realignment of Brock Road requires the installation of 46 wood poles and 4 steel poles, which are required in order to support the long conductor spans needed to cross Highway 407.

This work will also require the removal of 15 existing wood poles.

Scope 12: Highway 407 and Westney Road (Part 2)

This section requires the removal of the temporary pole line, and the construction of the permanent pole line. The work consists of installing 11 wood poles, and 2 steel poles, which are required to cross the highway.

This work will also require the removal of 14 existing wood poles.

Scope 13: Highway 401 and Highway 407 at Lakeridge Road

This section of the project requires the removal of the temporary pole line across Highway 401, and the installation of the permanent pole line. The work consists of installing 27 wood poles, and 2 steel poles, and the removal of 8 wood poles.

Project Cost Summary:	**$14.046 million gross**
Labour & Fleet	$6.805 million
Material	$5.449 million
Contractor/Other	$1.792 million

Name of Project	Highway 2 (Kingston Road) Road Widening – Bus Rapid Transit Corridor
Project Classification	System Access
Start Date	May 2013
In Service Date	December 2014
Capital Expenditure	2013 $1.024 million gross, $0.818 net 2014 $2.251 million gross, $1.832 million net Total $3.275 million gross, $2.65 million net

Overview

This system access project is required to accommodate the Region of Durham's plans to widen Highway 2 (Kingston Road) to create a Bus Rapid Transit corridor from Lakeridge Road, the eastern boundary of Ajax, to the western boundary of Pickering.

In 2013, the widening of Kingston Road creates a need to relocate Veridian assets at the intersections of Kingston Road and Salem Road, Kingston Road and Harwood Road, and along Kingston Road between Denmar Road and Southview Drive, crossing Brock Road.

In 2014, Veridian will need to relocate assets at the intersection of Kingston Road and Liverpool Road, and between Steeple Hill and Fairport Road, crossing Whites Road.

Overall, Veridian estimates that a capital contribution of $625,534 will be received from the Region of Durham in connection with this project.

Project Description

2013

At the intersection of Kingston Road and Salem Road, Veridian has moved 4 concrete poles and 0.15 km of underground cable, carrying a 13.8kV circuit.

At the intersection of Kingston Road and Harwood Road, Veridian moved 3 concrete poles, 0.1 km of overhead 44kV circuit, 0.1 km of overhead 13.8kV circuit, and 30 metres of underground circuit.

Along the section of Kingston Road between Denmar Road and Southview Drive, Veridian will move 34 wood poles, carrying 0.75 km of overhead 44kV circuit, and 0.75 km of overhead 27.6kV circuit.

2014

Along the section of Kingston Road between Steeple Hill and Fairport Road, Veridian will move 37 wood poles carrying 1.2 km of overhead 27.6kV circuit, and 0.9 km of underground 27.6kV circuit.

At the intersection of Kingston Road and Liverpool Road and the surrounding vicinity, Veridian will move 16 wood poles and 11 concrete poles carrying 1.25 km of overhead 44kV circuit, 1.65 km of overhead 27.6kV circuit, and 1.48 km of underground 13.8kV circuit.

The descriptions given above for 2014 work represent the best information available to Veridian at this time, but are subject to confirmation of final designs by the Region of Durham.

Year	Project	Gross	Contribution	Net
2013	BRT - Hwy #2 at Salem due to road widening (BRT) Ajax	$250,000	$60,000	$190,000
2013	BRT - Hwy #2 at Brock Road (Denmar x Southview), relocate existing feeders due to transit road widening (BRT) Pickering	$653,787	$115,975	$537,812
2013	BRT - Relocate overhead pole line on Highway #2 at Harwood Avenue, Ajax, due to road widening (BRT)	$120,000	$30,000	$90,000
2014	BRT - Hwy#2 (Steeplehill x Fairport) BRT - Pickering	$1,067,300	$224,133	$843,167
2014	BRT - Highway #2 at Liverpool Road, BRT - Pickering	$1,184,400	$195,426	$988,974
	BRT – TOTAL	$3,275,487	$625,534	$2,649,953

Project Cost Summary:	**$3.275 million gross**
Labour & Fleet	$1.600 million
Material	$1.200 million
Contractor/Other	$0.475 million

Name of Project	Long Term Load Transfer Eliminations - Various Locations
Project Classification	System Access
Start Date	October 2013
In Service Date	June 2014
Capital Expenditure	$1.250 million gross

General Information

This system access project is composed of a collection of sub-projects in different locations, all of which are required to meet the mandated termination of long term load transfers (LTLTs) by June 30, 2014, as directed by the Board at Section 6.5.4 of the Distribution System Code.

In undertaking and proposing the work described below, Veridian has sought the most cost-effective resolution of existing LTLTs. In some cases this has entailed an extension to Veridian's system, or the purchase by Veridian of the physical distributor's assets, while in other cases Veridian will transfer the customer(s) in question to the physical distributor. The actions and proposals set out below are consistent with the LTLT Elimination Plan filed by Veridian with the Board on November 30, 2012.

Project Description

Table 1 below summarizes the elements of Veridian's LTLT elimination plan, indicating the location of the LTLTs, whether the customers will be retained or transferred, the year of the work, and the costs.

ITEM #	Location	Disposition	YEAR	COST($)
1	Low Boulevard, Uxbridge	Retain	2014	$260,000
2	Lakeridge Road, Concession 9/Uxbridge Townline, Pickering	Retain/Transfer	2014	$60,000
3	Concession 10 at Hoxton Street, Pickering	Transfer	2014	$0
4	Concession 10 at Old Brock Road, Pickering	Retain	2014	$5,000
5	Concession 10 at Brock Road & Westney Road, Pickering	Transfer	2014	$0
6	Pickering/Markham Townline, Pickering	Retain	2014	$80,000
7	Lakeshore Blvd. & Riley Road, Newcastle	Retain/Transfer	2013	$350,000
8	Metcalf Street & Riley Road, Newcastle	Retain	2013	$300,000
9	Bellwood Drive, Newcastle	Transfer	2014	$0
10	Victoria Street & Maple Street, Port Perry	Retain/Transfer	2014	$170,000
11	Airport Parkway, Belleville	Retain	2014	$25,000
12	Martin Road, Bowmanville	Svc Not req’d	-	-
	TOTAL			$1,250,000

1. Low Boulevard, Uxbridge

At this location Veridian will purchase existing Hydro One underground distribution system assets, including transformers and high and low voltage cables, and connect them to the existing Veridian system to create a new loop feed in the area. The existing padmount transformers will be replaced with dual voltage units (8.32kV/27.6kV) in preparation for a voltage conversion project in the area. The voltage conversion project is not anticipated before 2019. Twelve residential customers are affected by the load transfer. In addition to LTLT resolution, this will provide system reinforcement and asset renewal benefits.

2. Lakeridge Road - Concession 9/Uxbridge Townline, Pickering

At this location, Veridian will connect an existing Veridian single phase line to a section of line currently owned by Hydro One Existing polemount transformers will be replaced with dual voltage units as a preparatory step to a voltage conversion once connected to the Veridian single phase line. Four customers will be retained as result of this work. The final step will be removal of an overhead crossing of Lakeridge Road. Three other customers at this location will be transferred to Hydro One.

3. Concession Road 10 at Hoxton Street, Pickering

At this location one customer will be transferred to Hydro One.

4. Concession Road 10 at Old Brock Road, Pickering

At this location Veridian will install will extend a low voltage distribution circuit on Hydro One poles, to service an existing streetlight.

5. Concession Road 10 at Brock Road & Westney Road, Pickering

At this location Veridian will transfer nine residential customers to Hydro One.

6. Pickering/Markham Townline, Pickering

At this location Veridian and Hydro One will move an existing disconnection switch which is the point of demarcation between the two systems slightly to the north. Veridian will purchase the assets south of the new switch and replace two poles to maintain service to three residential customers.

7. Lakeshore Blvd., & Riley Road, Newcastle

At this location Veridian will purchase Hydro One assets on Lakeshore Road and connect these to existing Veridian assets on Boulton Street, by installing 10 poles and approximately 0.8 km of conductor. The six transformers will then be converted to dual 4.16kV/13.8kV voltage. This will maintain service to ten residential customers. One residential customer on Riley Road will be transferred to Hydro One.

This project, together with the adjoining project described below, both serve the southwest area of Newcastle which is expected to be the subject of future development. These two projects combined afford an opportunity for asset renewal and system reinforcement, which will accommodate future growth (see attached map for South Newcastle). The 44kV to 4.16kV transformer which supplies this Area is also in poor condition and Veridian plans to convert the 4.16kV load to 13.8kV and remove this transformer from service.

8. Metcalf Street & Riley Road, Newcastle

At this location Veridian will purchase Hydro One assets east along Metcalf Street to Riley Road, then north along Riley Road to cross Highway 401 and connect with existing Veridian assets on Farrow Avenue. Five transformers will be converted to dual 4.16kV/13.8kV voltage. This will maintain service to eight residential customers. Due to their low height and large spans, existing Hydro One poles will not be reused. Veridian plans to install 43 wood poles of varying heights, including two 90 foot tall poles required to cross the 401.

Veridian anticipates that this area will see considerable future growth, due to its desirable location and improved transportation infrastructure such as the extensions of GO service and Highway 407. This asset acquisition, together with the one described above, will over the medium term enable Veridian to phase out obsolete 4.16kV assets currently serving the adjoining area and introduce a 13.8kV system capable of serving increased load with better reliability.

9. Bellwood Drive, Newcastle

At this location one residential customer will be transferred to Hydro One.

10. Victoria Street & Maple Street, Port Perry

At this location Veridian will purchase Hydro One assets to connect three existing customers on Victoria Street east of Old Simcoe Road to an existing Veridian padmount transformer on Hyland Crescent. Six customers on Maple Street and Victoria Street west of Old Simcoe Road will be transferred to Hydro One. This will maintain consistency of the service area borders on Victoria and Maple Streets as between Veridian and Hydro One.

11. Airport Parkway, Belleville

At this location Veridian will extend existing single phase primary line on Hydro One poles from an existing dead end to provide service to eight residential customers and one set of CNR railway signals.

12. Martin Road North, Bowmanville

Service no longer required at this location.

Evaluation Criteria

The trigger for these projects is a requirement for compliance with the Distribution System Code.

This project is a high priority for Veridian in order to maintain compliance.

This project will not have a material effect on existing levels safety, cyber-security, privacy, co-ordination, or interoperability.

This project does not provide material incremental environmental benefits.

Category-Specific Information: System Access Projects

The timing of these projects is dictated by the provisions of the Distribution System Code. Veridian has consulted with Hydro One in order to determine the most cost effective way to resolve existing LTLTs and associated technical requirements.

To minimize controllable costs, Veridian acquires equipment, materials, and external services such as construction of civil infrastructure through a procurement process (documented in Veridian's Procurement Policy provided at Exhibit 4, Tab 5, Schedule 1, Attachment 2) and installs the minimum equipment necessary to meet load and standards. In several instances Veridian has elected to resolve LTLTs by transferring customers in order to reduce costs.

In some instances, notably those of the Newcastle projects, Veridian intends to integrate its work to resolve LTLTs with other work on the distribution system to renew aged plant and reinforce the distribution system to meet higher loads more reliably.

Project Cost Summary:	**$1.250 million gross**
Labour & Fleet	$0.670 million
Material	$0.400 million
Contractor/Other	$0.180 million

Name of Project	New GS Services
Project Classification	System Access
Start Date	January 2013
In Service Date	December 2013
Capital Expenditure	$1.166 million gross, $0.000 million net

Overview

Veridian continued to experience growth in general service customers in 2013. Costs for these non-discretionary expenditures generally include installation of new 3-phase distribution transformers as well as ductwork and cabling required for connection to Veridian's distribution system.

The majority of expenditures reported under this project were necessary to connect new general service customers, with additional costs incurred for service upgrades at customer request. All gross costs were offset by capital contributions.

Project Description

The estimated number of three phase transformers, and the associated equipment, required for 2013 is 28, with 22 having been placed into service from January 2013 to the end of July 2013. Veridian's forecast is based on a review of previous annual quantities of general service installations as well as a qualitative assessment of economic factors. Additional consideration is given to the general residential building activity in its service territory, as general service construction typically follows new home construction. The forecast of general service installations is primarily used as an indication of possible gross capital costs for Veridian's capital planning. Due to the non-discretionary nature of this work, Veridian must, and does, respond to general service customer requests as they are received, regardless of any differences in the forecasted quantities of work required versus actual.

Project Cost Summary:	**$1.166 million gross**
Labour & Fleet	$0.250 million
Material	$0.666 million
Contractor/Other	$0.250 million

Name of Project	New Residential Services
Project Classification	System Access
Start Date	January 2013
In Service Date	December 2013
Capital Expenditure	$4.018 million gross, $2.278 million net

Overview

This system access project is to provide service to customers in new residential subdivisions, as well as for scattered new overhead and underground services outside of new subdivisions.

Project Description

Veridian forecasts that for 2013, it will install and close to net fixed assets 1,300 residential lots, at an average gross cost of $3,091 per lot, for a total gross expenditure of $4.018 million. Net expenditure is estimated to be $2.278 million, with the net cost per lot estimated to be $1,752. Veridian's forecast of residential subdivision lot connections is based on housing starts and communications with developers in Veridian's service area. As of July 30, 2013 a total of 726 lots had been connected.

2013 is the last year during which Veridian will include in its Economic Evaluation model the cost of upstream system enhancements, expressed as an amount per kW. Due to the implementation of changes in the Distribution System Code, starting in 2014 Veridian will absorb enhancement costs. As a result, average capital contributions in 2014 will be lower than they otherwise would have been.

Project Cost Summary:	**$4.018 million gross**
Labour & Fleet	$0.900 million
Material	$2.900 million
Contractor/Other	$0.218 million

Name of Project	Orono Creek Line Relocation
Project Classification	System Access
Start Date	December 2013
In Service Date	October 2014
Capital Expenditure	2013 \$0.258 million gross, \$0.039 net 2014 \$0.085 million gross, \$0.053 net Total \$0.343 million gross, \$0.092 million net

Overview

This system access asset relocation project is being undertaken by Veridian at the request of the Region of Durham, to enable the reconstruction of a bridge in the town of Orono. The current overhead feeder location impinges on the area required for construction, and creates a hazard for contractors using heavy equipment associated with bridge construction.

The project will be undertaken in two parts, the first of which is to construct an alternative supply to customers who are currently served by the feeder which is to be taken out of service to permit construction. That work will take place in December 2013.

The second part, to be done in 2014, is to reconstruct the existing feeder after bridge construction work has progressed to the point permitting that.

The Region of Durham will be making a capital contribution covering the majority of the cost for this work.

Project Description

To construct the alternative supply serving the customers currently supplied by the radial feeder being terminated to permit bridge construction, Veridian will install 10 wood poles, two single phase pole mounted transformers, and 280 metres of 8.32kV circuit. In addition the segment of the existing feeder line that conflicts with bridge construction will be removed.

To restore the feeder line in 2014, Veridian will install 4 wood poles, 1 polemounted transformer, and 100 metres of overhead line.

Project Cost Summary:	**$0.343 million gross**
Labour & Fleet	$0.200 million
Material	$0.143 million
Contractor/Other	$0.0 million

Name of Project	Retail Meters
Project Classification	System Access
Start Date	January 2013
In Service Date	December 2013
Capital Expenditure	$0.479 million gross

Overview

Veridian must install meters in association with the connection of new customers (except for unmetered scattered loads). This project is associated with the projects describing the addition of new residential and general service customers, described at Exhibit 2, Tab 3, Schedule 13.

Project Description

The expenditures for 2013 recorded under this project are for meter materials and installations associated with the expected addition of 1,300 new residential customers and 300 general service meters being installed in 2013. Forecast average costs per installation are $139 for residential meters and $994 for general service meters.

Up to the end of September, Veridian has installed 849 residential meters and 49 three phase general service meters. Any capital contributions received in connection with these additions were recorded in the corresponding customer addition projects.

Project Cost Summary	**$0.479 million gross**
Labour & Fleet	$0.279 million
Material	$0.200 million
Contractor/Other	$0.000 million

Name of Project	Rossland Road Relocation (Clearside X Southcott)
Project Classification	System Access
Start Date	October 2013
In Service Date	December 2013
Capital Expenditure	$0.385 million gross, $0.289 million net

Overview

This system access project is for the relocation of Veridian overhead infrastructure to accommodate a road-widening project being undertaken by the Region of Durham. Brock Road in Pickering will be widened and re-graded at the intersection of Rossland Road.

Project Description

A Hydro One transmission corridor crosses the intersection of Brock Road and Rossland Road diagonally, running southwest to northeast. Prior to the re-grading of the roadways, it was possible for Veridian to run its 27.6kV feeder overhead while maintaining the required electrical clearance between the overhead transmission and distribution lines. However, with the re-grading, that clearance could not be maintained without interfering with the overhead transmission lines such that Veridian is required to reconstruct a 500 metre portion of the feeder underground.

In order to underground this segment of the feeder, Veridian will employ contractors to trench such that the feeder can be fed through concrete encased underground ducts between the terminal poles carrying the feeder overhead east and west of the undergrounded section. Veridian's project is dependent on completion of the re-grading work.

Project Cost Summary	**$0.385 million gross**
Labour & Fleet	$0.100 million
Material	$0.160 million
Contractor/Other	$0.125 million

Name of Project	Westney Road N Road Relocation (Magill X Telford)
Project Classification	System Access
Start Date	August 2013
In Service Date	October 2013
Capital Expenditure	$1.475 million gross, $1.038 million net

Overview

This project is driven by the Region of Durham's request to move Veridian assets due to the widening of Westney Road from Magill to Telford (approximately 1.4km). A capital contribution of $437 thousand is expected from the Region of Durham.

Project Description

There are four feeders affected by this relocation: one 44kV, two 13.8kV, and one 27.6kV. Veridian will be installing 48 wood poles, one 44kV load interrupter switch, two 13.8kV load interrupter switches, 12km of conductor, 14 temporary switches for construction purposes, two primary cable duct structures, 950 metres of 28kV primary cable (energized at13.8kV), and 4 pole mounted transformers.

In addition, the project involves transferring 40 spans of Veridian owned fibre optic communication cable used by its SCADA system from the old poles to the new poles, and removing 38 wood poles. The cost of transferring the Veridian fibre is expected to be $20,000. Other communications cables will be moved by their respective owners and those costs are not included here.

Project Cost Summary:	**$1.475 million gross**
Labour & Fleet	$0.660 million
Material	$0.600 million
Contractor/Other	$0.215 million

Name of Project	Southeast Collector (SEC) Project
Project Classification	System Access
Start Date	January 2010
In Service Date	December 2013
Capital Expenditure	$2.006 million gross, $0 net (fully contributed)

Refer to Historical Project Descriptions found in Exhibit 2, Tab 2, Schedule 2 of this Rate Application.

Project Cost Summary:	**$2.006 million gross**
Labour & Fleet	$0.661 million
Material	$0.892 million
Contractor/Other	$0.453 million

Name of Project	Dundas Street Coleman to BayBridge
Project Classification	System Access
Start Date	January 2014
In Service Date	December 2014
Capital Expenditure	$2.200 million gross, $0.299 million net

General Information

This system access feeder relocation project is being undertaken at the request of the City of Belleville to accommodate its reconstruction of Dundas Street from Coleman Street to Bay Bridge Road, a distance of approximately 0.6 km. In order to accommodate the City's design, feeders which are currently overhead would be undergrounded over this segment of Dundas Street. However, the cost sharing arrangements between Veridian and any road authority such as the City of Belleville are such that cost sharing calculations will be based on only the cost that Veridian would otherwise have if the existing overhead were simply relocated to accommodate the road reconstruction (considered as like-for-like replacement). Additional costs for work requested by the road authority, but not required for technical reasons, will be fully contributed by the road authority. In this case, the gross cost of only relocating overhead Veridian plant without undergrounding, would be $1.196 million and Veridian's net cost would remain the same at $0.299 million.

Project Description

This project involves the undergrounding of one 44kV circuit and one 13.8kV circuit. Concrete encased duct bank will be installed for a distance of 600 metres to house the cables, consisting of 1850 metres of 1000 MCM 46kV cable, 1850 metres of 1000 MCM - 28kV cable, and 3360 metres of 1/0 28kV cable. In addition, 5 padmounted switchgear units, 2 single phase padmounted transformers, and 2 three-phase padmounted transformers will be installed. Fourteen existing concrete poles will also be removed.

Evaluation Criteria

The trigger for this project is the City of Belleville's street reconstruction project.

This project is a high priority for Veridian because of the obligation to respond to a road authority's request to relocate equipment and coordinate Veridian's work with that of the general construction.

This project will not have a material effect on existing levels on safety, cyber-security, privacy, co-ordination, or interoperability.

In addition to the economic stimulus provided by the investments in this project, the general project is expressly undertaken by the City of Belleville to stimulate economic re-development of its downtown core.

This project does not provide material incremental environmental benefits.

Category-Specific Information: System Access Project

The timing of this project is dependent upon and coordinated with the City of Belleville's construction plans, which at present are that this project is to be undertaken in 2014.

This project is being done at the request of the City of Belleville. Veridian has had only limited discussions with the City to advise it and determine the City's preferences. More Veridian design work will be done for this project once the City's detailed engineering plans are available.

To minimize controllable costs, Veridian acquires equipment, materials, and external services such as construction of civil infrastructure through a procurement process (documented in the Purchasing Policy found in section at Exhibit 4 Tab 5 Schedule 1 Attachment 2) and installs the minimum equipment necessary to meet load and standards. Additional civil infrastructure in the form of spare ducts will most likely be installed at the same time as this project would be seen as an opportunity for enhancement of its distribution system to easily incorporate any future system work. Refer to Exhibit 2, Tab 3, Schedule 8, for further details.

Given the nature of this project there were no other major alternatives (such as overhead) available that would meet the requirements.

Other than as discussed above, this project does not require evaluation of different system options. The final economic evaluation is not yet available.

Project Cost Summary:	**$2.200 million gross**
Labour & Fleet	$0.600 million
Materials	$0.950 million
Contractor/Other	$0.650million

Name of Project	Front Street (Dundas Street to Pinnacle Street)
Project Classification	System Access
Start Date	July 2014
In Service Date	December 2014
Capital Expenditure	$1.979 million gross, $0.279 million net

General Information

This system access feeder relocation project is being undertaken at the request of the City of Belleville to accommodate its reconstruction of Front Street from Dundas Street to Pinnacle Street, a distance of approximately 1.1 km. In order to accommodate the City's anticipated design, feeders which are currently underground will need to be relocated over this segment of Front Street. The standard cost sharing arrangement applies to this project. This work is being driven by an initiative of the City of Belleville, called "Build Belleville". It will consist of a four year program of projects focused on the infrastructure of the city and downtown revitalization efforts. Front Street is a major street in downtown Belleville and is targeted for utility reconstruction in 2014 with the road works being completed in 2015.

Project Description

This project involves the moving of an underground 13.8kV circuit. Concrete encased duct bank will be installed for a distance of 1,100 metres to house the conductors, consisting of 3,500 metres of 500MCM cable. In addition, 4 padmounted switchgear units and 6 three-phase padmounted transformers will be installed.

Evaluation Criteria

The trigger for this project is the City of Belleville's street reconstruction project.

This project is a high priority for Veridian because of the obligation to respond to a road authority's request to relocate equipment and coordinate Veridian's work with that of the general construction.

This project will not have a material effect on existing levels safety, cyber-security, privacy, co-ordination, or interoperability.

In addition to the economic stimulus provided by the investments in this project, the general project is expressly undertaken by the City of Belleville to stimulate economic re-development of its downtown core.

This project does not provide material incremental environmental benefits.

Category-Specific Information: System Access Project

The timing of this project is dependent upon and coordinated with the City of Belleville's construction plans, which at present are that this project is to be undertaken in 2014.

This project is being done at the request of the City of Belleville and Veridian has had limited discussions with the City to advise it and determine the City's preferences. Detailed designs from the City are still pending at this time (September 2013).

To minimize controllable costs, Veridian acquires equipment, materials, and external services such as construction of civil infrastructure through a procurement process (documented in

Veridian's Procurement Policy provided at Exhibit 4, Tab 5, Schedule 1, Attachment 2) and installs the minimum equipment necessary to meet load and standards.

Veridian assessed its distribution system in this area and determined that no other enhancement work was required or justified at this time.

Given the nature of this project there were no other major alternatives (such as overhead) available that would meet the requirements.

Other than as discussed above, this project does not require evaluation of different system options. The final economic evaluation is not yet available.

Project Cost Summary:	**$1.979 million gross, $0.279 million net**
Labour & Fleet	$0.170 million
Materials	$0.759 million
Contractor/Other	$1.050 million

Name of Project	Rossland Road (Southcott to Church)
Project Classification	System Access
Start Date	March 2014
In Service Date	May 2014
Capital Expenditure	$0.736 million gross, $0.509 million net

General Information

This system access asset relocation project is to accommodate plans by the Town of Ajax to widen Rossland Road from Church Street to Southcott Road. Veridian's existing pole line conflicts with the road-widening project, necessitating its relocation by Veridian.

Project Description

Veridian's conflicting pole line in this area runs a length of approximately 1.7 km, and carries one 44kV circuit, one 27.6kV circuit and one 13.8kV circuit. To relocate the pole line, Veridian will install 40 wood poles, transfer the circuits, and remove 37 wood poles.

Veridian estimates the capital contribution from the Town of Ajax applicable to this project to be $227,000.

Evaluation Criteria

The trigger for this project is the Town of Ajax's street reconstruction project.

This project is a high priority for Veridian because of the obligation to respond to a road authority's request to relocate equipment and coordinate Veridian's work with that of the general construction.

This project will not have a material effect on existing levels safety, cyber-security, privacy, co-ordination, or interoperability.

In addition to the economic stimulus provided by the investments in this project, the general project is undertaken by the Town of Ajax to reduce congestion and improve civic infrastructure, which enables economic activity and growth.

This project does not provide material incremental environmental benefits.

Category-Specific Information: System Access Project

The timing of this project is dependent upon and coordinated with the construction plans of the Town of Ajax, which at present are to perform this construction in 2014.

Veridian has consulted with the Town of Ajax to advise it and determine the Town's preferences with respect to this project.

To minimize controllable costs, Veridian acquires equipment, materials, and external services such as construction of civil infrastructure through a procurement process (documented in Veridian's Procurement Policy provided at Exhibit 4, Tab 5, Schedule 1, Attachment 2) and installs the minimum equipment necessary to meet load and standards.

Veridian has made an assessment of its distribution system in this area and has determined that no other enhancement or asset renewal projects are necessary to be combined with this project at this time. Given the nature of this project there are no other alternatives that would be preferable (for example, undergrounding the feeders).

Other than as discussed above, this project did not require comparison of other alternatives. Final economic evaluations are not yet available for 2014 projects.

Project Cost Summary:	**$0.736 million gross**
Labour & Fleet	$0.300 million
Materials	$0.350 million
Contractor/Other	$0.086 million

Name of Project	New GS Services and Transformers
Project Classification	System Access
Start Date	January 2014
In Service Date	December 2014
Capital Expenditure	$1.400 million gross, $0.000 million net

General Information

For this system access project, Veridian estimates that growth in general service customers in 2014 will continue at a slightly higher rate than in 2013. For 2014, 35 new three phase transformer installations are forecast, compared to the 28 estimated in 2013. Costs for these non-discretionary expenditures generally include installation of ductwork and cabling required for connection to Veridian's distribution system, as well as the new 3-phase distribution transformers.

The majority of expenditures reported under this project are necessary to connect new general service customers, with additional costs incurred for service upgrades at customer request. All gross costs are expected to be offset by capital contributions.

Project Description

The estimated number of new three phase transformers and associated equipment required for 2014 is 35. Veridian's forecast is based on a review of previous annual quantities of general service installations as well as a qualitative assessment of economic factors. Additional consideration is given to the general residential building activity in Veridian's service territory, as general service construction typically follows new home construction. The forecast of general service installations is primarily used as an indication of possible gross capital costs for

Veridian's capital planning. Due to the non-discretionary nature of this work, Veridian must, and does, respond to general service customer requests as they are received, regardless of any differences between the forecasted quantities of work required versus actual.

Evaluation Criteria

The trigger for this project is the flow of connection requests from general service customers.

This project is a high priority for Veridian because of the obligation to respond to a customer's request to connect to Veridian's distribution system.

This project will not have a material effect on existing levels of safety, cyber-security, privacy, co-ordination, or interoperability.

In addition to the economic stimulus provided by the investments in this project the connection of new customers enables economic growth in Veridian's service area and beyond.

This project does not provide material incremental environmental b enefits.

Category-Specific Information: System Access Project

The timing of installation of individual services and transformers is dependent upon the customer's schedule and the receipt of necessary approvals, such as from the ESA.

Veridian generally discusses with customers any available alternative designs and it is up to the customer to select among any alternatives though in most cases, alternatives are limited. Customers provide Veridian with their preferences which Veridian attempts to accommodate within the constraints imposed by the existing equipment configuration, statutory and other external requirements, and within the framework of its own standards. The customer's load characteristics are largely determinative of service and transformer characteristics and capacities, and alternative designs are generally not available except at higher cost.

To minimize controllable costs, Veridian acquires equipment, materials, and external services such as construction of civil infrastructure through a procurement process (documented in Veridian's Procurement Policy provided at Exhibit 4, Tab 5, Schedule 1, Attachment 2) and installs the minimum equipment necessary to meet load and standards.

The connection of new individual GS services generally does not involve other planning priorities. However, large new general service loads may trigger the need for system expansion or reinforcement of Veridian's upstream distribution facilities, which are documented separately where they occur. The scope of this project is confined to new GS services and transformers.

Other than as discussed above, connection of new GS services does not require evaluation of different system options.

Project Cost Summary:	**$1.400 million gross**
Labour & Fleet	$0.400 million
Material	$0.900 million
Contractor/Other	$0.100 million

Name of Project	Renewable Energy Project - Ajax
Project Classification	System Access
Start Date	January 2014
In Service Date	March 2014
Capital Expenditure	$0.700 million gross

General Information

This system access project is a renewable energy generation enabling investment required to connect a new 25 MW generator located in Ajax. To accept the generator output onto Veridian's system, it is necessary to expand Veridian's system by rebuilding an existing 44kV pole line to make provision for a new 44kV circuit. This project is eligible for Provincial Benefit treatment, as documented at 'Part "B" of Appendix 2-FA and Appendix 2-FC. Appendix 2-FA and 2-FC can be located in Exhibit 2, Tab 3, Schedule 10, and Attachment 3 of this rate application. It is the only REG system expansion project Veridian forecasts for 2014. The generator requires this connection to be in service by March 2014.

Project Description

This project has two components, the major one of which is the work necessary to accept the generator output. This will require the existing pole line to be rebuilt to accept an additional 44kV circuit. The rebuild will involve removing eleven 60-foot poles and installing ten 70-foot poles, and the associated conductor together with one 44kV load interrupter switch.

The cost of this work is $0.5 million. Under the Board's $90/kW formula for REG system expansion investments, this entire cost is to be borne by Veridian. Connection costs will be borne 100% by the generator.

The second component, which is not essential to the REG connection, involves Veridian installing two additional 44kV load interrupter switches for the purpose of improving its ability to switch loads in the south Ajax area, where the generator project is located. This in turn will improve reliability in this area, which, as is documented in this application, has experienced poorer-than-average reliability over the past several years. The cost for the two additional load interrupter switches is $0.2 million. This work is being done coincidentally with the REG project because it is cost effective to do so while working on the same equipment.

Evaluation Criteria

The trigger for this project is the need to connect the renewable generator. Since that work presents an opportunity for Veridian to cost effectively install equipment to improve reliability in the area, a secondary system service driver is reliability improvement in an area of relatively poor reliability.

This project is a high priority for Veridian given its obligation to connect renewable generation and the customer's need for an in-service date early in 2014.

This project is not expected to have material effects on existing levels of safety, cyber-security, privacy, co-ordination or interoperability.

This project is expected to have positive effects on economic development and environmental benefits, since it enables renewable generation pursuant to Ontario government policy and improves reliability of electricity supply.

Category-Specific Information: REG Access Projects

As noted, the generator to be connected requires service by March 2014, which is largely determinative of the timing of this project.

Veridian has consulted extensively with the generator to establish the technical requirements for the connection to Veridian's distribution system, as well as its timing.

To minimize controllable costs, Veridian acquires equipment, materials, and external services such as construction of civil infrastructure through a procurement process (documented in Veridian's Procurement Policy provided at Exhibit 4 Tab 5 Schedule 1 Attachment 2) and installs the minimum equipment necessary to meet load and standards. The installation of the two additional load interrupter switches at the time the REG connection work is being done reduces costs relative to what they would have been otherwise were that work done separately. Given the location of this generator and the configuration of Veridian's system in the area, there were no other preferable (more cost effective) alternative methods for connection of the generator.

In assessing the system impacts of connecting this renewable generator, Veridian has determined that there are no material impacts arising from this project apart from those described above.

Project Cost Summary:	**$0.700 million gross**
Labour & Fleet	$0.300 million
Materials	$0.300 million
Contractor/Other	$0.100 million

Name of Project	New Residential Services
Project Classification	System Access
Start Date	January 2014
In Service Date	December 2014
Capital Expenditure	$5.198 million gross, $3.370 million net

General Information

This system access project is to provide service to new residential customers.

Project Description

Veridian forecasts that for 2014, it will install and close to net fixed assets 1,700 subdivision lots, at an average gross cost of $3,058 per lot, for a total gross expenditure of $5.198 million. Associated capital contributions for subdivision lots are estimated at $1.828 million, or an average of $1,075 per lot. Veridian's forecast of residential connections is based on housing starts and communications with developers in Veridian's service area.

2013 was the last year during which Veridian included in its Economic Evaluation model the cost of upstream system enhancements, expressed as an amount per kW. Due to the implementation of changes in the Distribution System Code, starting in 2014 Veridian will absorb Enhancement costs. As a result, average capital contributions in 2014 are lower than they otherwise would have been.

Evaluation Criteria

The trigger for this project is the flow of connection requests from subdivision developers and individual residential customers.

This project is a high priority for Veridian because of the obligation to respond to a customer's request to connect to Veridian's distribution system.

This project will not have a material effect on existing levels of safety, cyber-security, privacy, co-ordination, or interoperability.

In addition to the economic stimulus provided by the investments in this project, the connection of new customers enables economic growth in Veridian's service area and beyond.

This project does not provide material incremental environmental benefits.

Category-Specific Information: System Access Project

The timing of the installation of subdivision services and associated infrastructure is dependent on the developer's schedule, which Veridian strives to accommodate. Installation of individual underground and overhead services is dependent upon the customer's schedule and the receipt of necessary approvals, such as from the ESA.

Veridian completes the design and attempts to incorporate customers' preferences within the constraints imposed by the existing equipment configuration, statutory and other external requirements, and its own standards.

To minimize controllable costs, Veridian acquires equipment, materials, and external services such as construction of civil infrastructure through a procurement process (documented in the Veridian's Purchasing Policy provided at Exhibit 4, Tab 5, Schedule 1, Attachment 2) and installs the minimum equipment necessary to meet load and standards.

Connection of new individual residential services generally does not involve other planning priorities. Connection of subdivisions almost always requires expansion of Veridian's distribution system and may occasion enhancements of Veridian's existing system, for example by increasing feeder and/or substation capacity through the addition of new conductors and transformers or voltage conversions. In some circumstances new capacity requirements may coincide with requirements to renew existing infrastructure.

When assessing the system requirements to serve a new subdivision Veridian considers these factors and where justified integrates other work for renewal or reinforcement purposes with expansion work so as to minimize overall costs and inconvenience to the public resulting from construction operations.

Veridian's standard infrastructure within new subdivisions is underground in duct with padmounted transformers and other associated equipment. Veridian's experience is that neither developers nor eventual subdivision homeowners tolerate overhead local distribution plant in new subdivisions. However, except where it is necessary to locate distribution plant underground for other reasons such as clearances, Veridian's standard infrastructure along major roads to reach the subdivisions is overhead. Final economic evaluations are not available for 2014 connections.

Project Cost Summary:	**$5.198 million gross**
Labour & Fleet	$1.400 million
Material	$3.312 million
Contractor/Other	$0.486 million

Name of Project	Airport Parkway West, new Industrial Area
Project Classification	System Access
Start Date	June 2014
In Service Date	September 2014
Capital Expenditure	$0.307 million gross

General Information

This system access project is being undertaken at the request of the City of Belleville in order to support the development of a parcel of land for new industrial purposes in 2014. At present, there is no service to the area.

Discussions are planned with the City of Belleville to finalize the contributed capital amount.

Project Description

In order to provide service to the area, Veridian will extend an existing 44kV and 13.8kV poleline by a length of 1.1 km. This will involve the installation of approximately 21 poles and related equipment to carry 2 - 44kV and 2 - 13.8kV circuits.

Evaluation Criteria

The trigger for this project is the City of Belleville's plan to develop these lands into an industrial park. That development requires electrical service.

This project is a high priority for Veridian because of the obligation to provide service to customers in Veridian's service area.

This project will not have a material effect on existing levels on safety, cyber-security, privacy, co-ordination, or interoperability.

In addition to the economic stimulus provided by the investment in this project, the general project is being undertaken by the City of Belleville to diversify its economic base, and increase economic activity and employment within the City.

This project does not provide material incremental environmental benefits.

Category-Specific Information: System Access Project

The timing of this project is dependent upon the City of Belleville's development plans, which at present are to perform this construction in 2014.

Veridian has had initial discussions with the City of Belleville to advise it and determine the City's preferences with respect to this project. The City does not have detailed plans completed at the time of writing (September 2013).

To minimize controllable costs, Veridian acquires equipment, materials, and external services such as construction of civil infrastructure through a procurement process (documented in the Purchases of Non-Affiliate Services section at Exhibit 4 Tab 5 Schedule 1 Attachment 2) and installs the minimum equipment necessary to meet load and standards.

Veridian has made an assessment of its distribution system in this area and has determined that no other enhancement or asset renewal projects are necessary to be combined with this project at this time. Given the location of this project there are no other alternatives that would be preferable (for example, undergrounding the feeders or supplying the area from an alternate source).

Other than as discussed above, this project did not require comparison of other alternatives. Final economic evaluations are not yet available for 2014 projects.

Project Cost Summary:	**$0.306 million gross**
Labour & Fleet	$0.150 million
Materials	$0.100 million
Contractor/Other	$0.056 million

Name of Project	Port Hope-Relocation of 44kV Pole Line
Project Classification	System Access
Start Date	January 2014
In Service Date	December 2014
Capital Expenditure	$0.625 million gross $0.0 million Net

General Information

This system access project is to relocate a portion of a 44kV feeder line at the request of a customer which wishes to expand its industrial facility. The cost will be entirely covered by a capital contribution from the customer.

Project Description

Veridian will relocated approximately 0.5 km of 44kV pole line, presently adjacent to the customer's facility, to enable the expansion of that facility.

Evaluation Criteria

The trigger for this project is the request from the general service customer.

This project is a high priority for Veridian because of the need to enable the expansion of the industrial facility.

This project will not have a material effect on existing levels of safety, cyber-security, privacy, co-ordination, or interoperability.

In addition to the economic stimulus provided by the investments in this project, the completion of this work directly enables economic growth in Veridian's service area and beyond.

This project does not provide material incremental environmental benefits.

Category-Specific Information: System Access Project

The timing of this project is contingent upon the customer's construction schedule.

The customer has advised Veridian of it preferences which Veridian will attempt to accommodate within the constraints imposed by the existing equipment configuration and its standards.

To minimize controllable costs, Veridian acquires equipment, materials, and external services such as construction of civil infrastructure through a procurement process (documented in the Procurement Policy provided at Exhibit 4, Tab 5, Schedule 1, Attachment 2), and installs the minimum equipment necessary to meet load and standards.

No other planning considerations are applicable to this project.

No alternative project designs are applicable to this project.

Project Cost Summary:	**$0.625 million gross**
Labour & Fleet	$0.325 million
Materials	$0.285 million
Contractor/Other	$0.015 million

Name of Project	Retail Meters
Project Classification	System Access
Start Date	January 2014
In Service Date	December 2014
Capital Expenditure	$0.455 million

General Information

Veridian must install meters in association with the connection of new customers (except for unmetered scattered loads). This project is associated with the projects describing the addition of new residential and general service customers, described at Exhibit 2, Tab 3, Schedule 13.

Project Description

The expenditures for 2014 recorded under this project are for meter materials and installations associated with the addition of 1,700 new residential and 167 general service meter installations in 2014. Forecast average costs per installation are $139.75 for residential meters and $1,296 for general service meters. Any capital contributions received in connection with these additions will be recorded in the corresponding customer addition projects.

Evaluation Criteria

The trigger for this project is the flow of connection requests from subdivision developers and individual residential customers.

This project is a high priority for Veridian because of the obligation to respond to a customer's request to connect to Veridian's distribution system.

This project will not have a material effect on existing levels of safety, cyber-security, privacy, co-ordination, or interoperability.

In addition to the economic stimulus provided by the investments in this project, the connection of new customers enables economic growth in Veridian's service area and beyond.

This project does not provide material incremental environmental benefits.

Category-Specific Information: System Access Project

The timing of installation of individual meters is dependent upon the customer's schedule and the receipt of necessary approvals, such as from the ESA.

Customers provide Veridian with their preferences regarding service type, which then generally dictates the meter type installed.

To minimize controllable costs, Veridian acquires equipment, materials, and external services such as construction of civil infrastructure through a procurement process (documented in Veridian's Procurement Policy provided at Exhibit 4, Tab 5, Schedule 1, Attachment 2) and installs the minimum equipment necessary to meet load and standards.

Installation of new meters generally does not involve other planning priorities but in the case of smart meters is consistent with Veridian's advanced metering infrastructure.

Alternative project designs are not applicable once service type is determined.

Other than as discussed above, installation of new meters does not require evaluation of different system options.

Project Cost Summary:	**$0.455 million gross**
Labour & Fleet	$0.250 million
Material	$0.205 million
Contractor/Other	$0.0 million

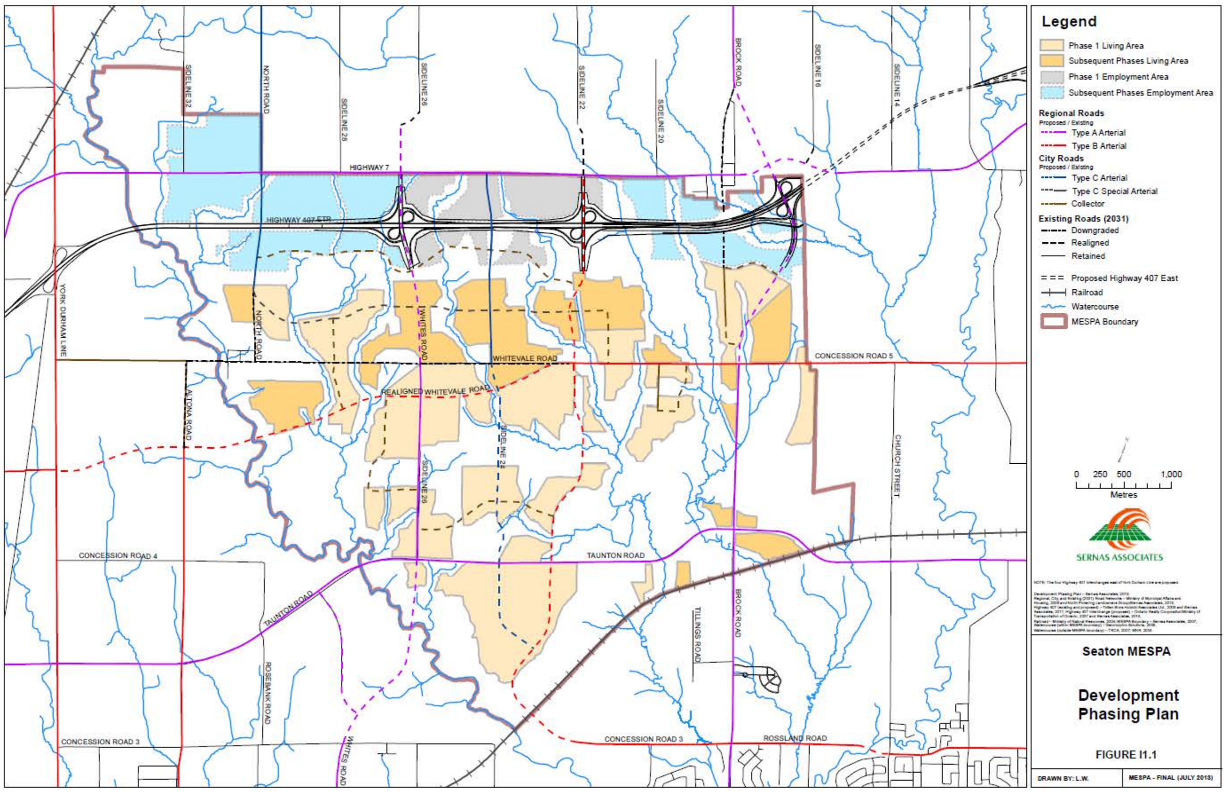
Name of Project	Taunton Road (Church to Brock): Three 27.6kV Circuits
Project Classification	System Access
Start Date	March 2014
In Service Date	May 2014
Capital Expenditure	$1.332 million gross

General Information

This system access project is required to provide service to the Seaton development area in north Pickering (see Figure 1 Seaton Development-North Pickering). The Seaton community has been planned with occupation of homes beginning in 2015 and development continuing for six years in the currently approved phase of the development. Additional lands for residential homes have been allocated but not approved at this time. The City of Pickering's development plan for Seaton projects the ultimate population of the area, including all residential lands, is expected to be over 66,000, with 13,090 single and semi-detached homes, 6,540 townhouses, and 2,180 apartments, together with associated commercial, industrial, and municipal developments. Approximately 1,700 homes are expected to require service in 2015, and prior to this construction power will be required. Relative to the existing land use, this development will create substantial new load requiring expansion of Veridian's distribution system to serve. The only available capacity in the area to serve this new load comes from Veridian owned 27.6kV feeders emanating from Hydro One's Whitby Transformer Station (230kV to 27.6kV). This project will be followed with a further extension of the feeders from the termination of this project to the Seaton development. It will be necessary to build additional feeders in the future to service the overall electrical demand in the area. These projects are not included in this narrative and are not planned for the 2014 Test Year.

Veridian estimates that it will not receive any capital contributions toward the cost of this system expansion.

Figure 1: The Seaton Development - North Pickering



Project Description

Veridian currently has three 27.6kV feeders from the Whitby transformer station, providing service to north Ajax, adjacent to the expected Seaton development. Veridian's feeders presently end at Church Street, and Veridian plans to extend those feeders by 1.3km along Taunton Road. This will require the installation of 58 wood poles and 3.9km of 3-phase, 28kV conductor, along with associated equipment. A substation will not be required given the distribution voltage of 27.6kV.

Evaluation Criteria

The trigger for this project is the imminent development of Seaton.

This project is a high priority for Veridian because of the obligation to connect new customers in Veridian's service area, in a timely manner so as to enable the planned construction of this new model community.

This project will not have a material effect on existing levels of safety, cyber-security, privacy, co-ordination, or interoperability.
In addition to the economic stimulus provided by the investment in this project, the planned development of the Seaton area will provide needed new housing and associated industrial, commercial, and municipal development. Economic benefits from the initial construction and ongoing uses of these lands are expected to be substantial.

The Veridian expansion project itself does not provide material incremental environmental benefits.

Category-Specific Information: System Access Project

The timing of this project is dependent upon and coordinated with the development of the Seaton area, which is planned to begin construction in 2014 with occupancy starting in 2015.

Veridian has consulted extensively with the City of Pickering and the Seaton Landowners Group (the developers) to assess the electrical needs of the development and their timing.

To minimize controllable costs, Veridian acquires equipment, materials, and external services such as construction of civil infrastructure through a procurement process (documented in the

Veridian's Procurement Policy provided at Exhibit 4 Tab 5 Schedule 1 Attachment 2) and installs the minimum equipment necessary to meet load and standards.

Veridian has made an assessment of its distribution system in this area as well as the existing high voltage transformation capacity. The only transformer station capacity available in the area to serve this new load is located at Hydro One's Whitby Transformer Station (230kV to 27.6kV), approximately 10 km east of the Seaton development on Halls Road north of Taunton Road. As noted above, Veridian currently has three 27.6kV feeders from the Whitby transformer station, providing service to north Ajax, adjacent to the Seaton development. Veridian has determined that the most cost effective way for it to provide service to the Seaton development in the short term is to extend these existing feeders, which have the required capacity, along Taunton Road and into the Seaton community.

Given the location and timing of this project there are no other alternatives in the short term that would be preferable (for example, serving the load from a more distant transformer station).

Veridian anticipates that the capacity available from the Whitby TS will be adequate to serve the Seaton area for the next 5 years. The feeders referenced in this project represent the extension of 3 of the 6 feeders emanating from Whitby TS that will service this development in total. As development is expected to continue beyond the 5 year horizon mentioned above, Veridian anticipates it will be necessary to add additional TS capacity and have it in service by the end of 2018. It will be noted in Appendix 2-AB that Veridian has allocated $21M in 2018 for the potential construction expense for the new TS required. Veridian will monitor the load growth in the Seaton area and pace any spending accordingly. The final decision on whether this additional TS will be built, and/or owned, by Veridian is subject to a pending business case analysis not completed by Veridian at this time (September 2013). It is anticipated that this analysis will be complete in 2014. As well, this anticipated TS capacity requirement will be included in the Regional Planning process just recently begun for Veridian in the GTA East region. No output from that process is available at this time.

Project Cost Summary:	**$1.332 million gross**
Labour & Fleet	$0.631 million
Materials	$0.601 million
Contractor/Other	$0.100 million

Material Investments - 2013 and 2014 - System Renewal Category

Name of Project	Reactive Pole Replacements
Project Classification	System Renewal
Start Date	January 2013
In Service Date	December 2013
Capital Expenditure	$0.752 million gross

Overview

Veridian routinely has to replace isolated poles or small groups of poles on a reactive basis to address conditions which require remediation. This can occur due to storm damage, poles becoming bent or out of plumb, fires, or the pole being found to be in unacceptable condition otherwise (for example, with respect to remaining strength) upon inspection. The expenditures reported for this project are for isolated reactive pole replacements; planned or programmatic pole replacements are reported under other projects.

Project Description

For 2013, Veridian estimates that 94 poles will be replaced on a reactive basis at an average cost of $8,000. Under reactive replacement, poles are replaced like-for-like, including cross arms and hardware used to frame the poles. Veridian has replaced 39 poles as of September 30, 2013, at a cost of $0.305 million, with an average cost per pole replaced of $7,824. (Please see table below).

Pole Type	No. of Poles Replaced	Cost Per Pole($)	Total($)
44KV Wood Pole	7	$12,122	$84,854
Distribution Wood Pole	32	$6,884	$220,288
Total Costs to Date	39	$7,824	$305,142

Project Cost Summary:	**$0.752 million gross**
Labour & Fleet	$0.620 million
Material	$0.094 million
Contractor/Other	$0.38 million

Name of Project	Reactive Transformer and Component Replacements
Project Classification	System Renewal
Start Date	January 2013
In Service Date	December 2013
Capital Expenditure	$0.9 million gross

Overview

Veridian routinely has to replace transformers and associated components on a reactive basis when those transformers fail unpredictably or present unacceptable conditions upon inspection. This can occur due to vehicle collisions, asset deterioration, overloading, and other factors. Transformer replacement on a planned or programmatic basis is reported under other projects.

Project Description

In 2013, Veridian has reactively replaced 64 padmount transformers and 37 polemount transformers to the end of September, with spending of $760,000. Based on 2013 experience to date, it is forecast that an additional 15 padmount transformers and 10 polemount transformers during the balance of the year for a total of 126 in 2013. In addition, associated equipment such as lightning arrestors and animal guards were or will be replaced where necessary. Spending in 2013 has been slightly lower than the average of 2010-2013 actuals due to lower non-transformer component replacements.

Project Cost Summary:	**$0.9 million gross**
Labour & Fleet	$0.3 million
Material	$0.6 million
Contractor/Other	$0.0 million

Name of Project	South Ajax Cable Replacement Projects-Various
Project Classification	System Renewal
Start Date	September 2012
In Service Date	December 2013
Capital Expenditure	2012 - $1.539 million 2013 - $1.875 million Total - $3.414 million gross

Refer to Historical Project Descriptions found in Exhibit 2, Tab 2, Schedule 2 of this Rate Application.

Project Cost Summary:	**$3.414 million gross**
Labour & Fleet	$0.457 million
Material	$0.889 million
Contractor/Other	$2.068 million

Name of Project	Gravenhurst Storm Damage Repairs - July 2013
Project Classification	System Renewal
Start Date	July 2013
In Service Date	August 2013
Capital Expenditure	$0.799 million gross

Overview

This emergency restoration system renewal project was caused by a violent storm that swept through the Gravenhurst area on July 19, 2013. High winds struck the area, which is heavily treed, causing thousands of trees to fall. In many instances, overhead infrastructure of both Veridian and Hydro One was destroyed or damaged by tree falls. Veridian's supply from Hydro One was disrupted for 11 hours on the 19th.

Veridian marshaled all resources available to it to immediately begin restoration work. The work was significantly complicated, with progress impeded by the fact that tree falls blocked many access routes for a prolonged period. Power restoration and equipment remediation work continued for eleven straight days, with crews working sixteen hour days.

Project Description

This project restored power to the entire Veridian Gravenhurst service area after significant damage to overhead equipment caused by a powerful storm. Veridian deployed all available internal resources to the project and also dispatched crews made available by Whitby Hydro and Hydro One. In addition, Veridian engaged local contractors to assist in the work of clearing fallen trees from access routes and equipment locations.

Initial assessment of the damage was difficult and complex due to the access impediments created by fallen trees. In more remote locations, and particularly for customers located on islands, it was necessary to utilize Hydro One helicopters to survey pole lines and identify damaged or faulted equipment.

A broad range of work was required for restoration. Clearing of fallen trees and vegetation was required everywhere. In some instances, faults caused by fallen limbs where infrastructure was not otherwise damaged could be cleared by simply removing the interfering vegetation. In other cases, conductors, poles, transformers and other associated equipment like switches were brought down by fallen trees and had to be reconstructed. In total, 36 wood poles and 24 transformers were completely replaced. Damaged equipment was repaired where possible. This occurred in dozens of other locations.

Current costs for storm repairs totaled $0.799 million. At the time of preparation of this evidence (September 14, 2013), Veridian had not determined all final costs. Table 1 below sets out the breakdown of costs.

Table 1: Gravenhurst Storm Damage Restoration Capital Costs

Item	Billed to Sept 14, 2013 ($)
Materials	$121,788
Contractor (Vacuum Excavator)	$4,600
Contractor (Lines)	$185,042
Contractors (Tree trimming)	$105,913
Misc Purchases	$9,086
Lines Labour Regular Time	$153,599
Lines Labour Overtime	$157,089
Fleet	$62,000
Total	$799,117

Project Cost Summary:	**$0.799 million gross**
Labour & Fleet	$0.373 million
Material	$0.122 million
Contractor/Other	$0.304 million

Name of Project	New Feeder - Port Hope Croft Street
Project Classification	System Renewal
Start Date	February 2014
In Service Date	April 2014
Capital Expenditure	$0.357 million gross

General Information

This system renewal project is to replace an aged segment of 44kV pole line running through a difficult-to-access area with a new pole line to be constructed in the road allowance of a new road to be built by the Municipality of Port Hope on adjacent land.

The existing pole line segment is located on an easement through green space and is without road access. It has been difficult to maintain and inspection indicates that it is now in poor condition, with the poles exhibiting diminished strength, and wood pecker damage, such that they require replacement.

In 2014, the Municipality of Port Hope plans to build an extension of Croft Street from the end point of its existing western section to Rose Glen Road, as depicted in Figure 1 below. Veridian plans to coordinate its construction of the new pole line segment with that road construction.

Project Description

This project will involve the installation of 14 poles carrying one 44kV circuit, and one 27.6kV circuit, together with associated equipment. The old pole line segment will then be decommissioned and removed.

Figure 1: Croft Street Extension

Evaluation Criteria

The principal trigger for this project is the need to rectify the poor condition of the pole line segment running through the easement. In the absence of the Municipality of Port Hope's planned extension of Croft Street, this work would still be required but would it be more expensive to build the segment and to maintain it on an ongoing basis.

From the perspective of system renewal, this project is a medium to high priority for Veridian, given the poor condition of the existing pole line and the consequential risks that it poses to safety and reliability. Although the road construction project is externally initiated and unrelated to Veridian's assets, that element introduces an opportunity for Veridian to coordinate its construction with that of the Municipality's and place its assets in the road allowance which will permit easier and lower cost maintenance for the life of the new pole line segment. Therefore the Municipality's construction schedule introduces a window of opportunity for Veridian's construction in 2014 that will be lost if Veridian defers this work.

Two other alternatives exist for this work. The first is to rebuild the pole line segment in place, through the easement without road access. Veridian rejected this alternative since it would simply perpetuate the problems associated with the existing line placement. The second alternative would be to defer this work until the Croft Street extension is built and in use by the public. Veridian sees significant disadvantages with that alternative, since it increases the risk that the existing pole line could fail catastrophically during a storm and create a prolonged outage due to the difficulty of restoring the line reactively under adverse conditions without road access. Veridian would also prefer to avoid the disruption to the use of the road that would occur if Veridian's construction were to take place after the road is in active use by the public. Other options, such as undergrounding the equipment, are unnecessary and uneconomic.

It is necessary to renew this pole line over the near term to address safety risks associated with the poor condition of the existing poles.

This project is not expected to have material effects on cyber-security, privacy, coordination, interoperability, economic development or the environment.

Category-Specific Information: System Renewal Projects

The assets to be replaced by this project are in poor condition as noted above. They were originally installed in approximately 1950, and are at or near end-of-life. Were one or more of the existing poles to fail due to wind loads, tree falls, or other stresses, it is likely that a prolonged outage would occur due to the difficulty of effecting repairs in an area with limited access. In addition, severe safety risks to the public are created whenever poles fail catastrophically.

Such a failure would affect approximately 2,000 residential and commercial customers. This is a discrete project rather than a program of activity and therefore Veridian's only options are around the timing of the project. As explained above, Veridian seeks to coordinate this project with the road construction in order to minimize costs and disruption to the public.

Veridian estimates that by moving the pole line segment to a location with road access, average annual maintenance costs for that line segment can be reduced by approximately $3,000 annually, due to reduction in tree trimming and operations costs.

Project Cost Summary:	**$0.357 million gross**
Labour & Fleet	$0.150 million
Materials	$0.150 million
Contractor/Other	$0.057million

Name of Project	Overhead Line Switches Replacement Program, various locations
Project Classification	System Renewal
Start Date	January 2014
In Service Date	December 2014
Capital Expenditure	$0.706 million gross

General Information

This project is for the replacement of critical, high-voltage line switches that are at or past end-of-life and have large reliability and system operability impacts upon failure. Veridian has more than 4,000 overhead line switches in operation on its system. These fall into several categories according to their specific designs and functions, and have varying degrees of criticality according to their location on the distribution system and the amount of load they carry. Generally, line switches are critical pieces of equipment because they both conduct and control the flow of electricity on the distribution system. They are used to isolate faults to minimize the reliability impacts of outages, and for routine switching purposes to a permit load transfers and maintenance operations.

Load interrupter switches (LIS) are one type of overhead line switch that are capable of operation under load (as distinct from other switch types which must be operated under no-load conditions). LIS operate at various voltage levels but generally the 44kV LIS carry the highest loads and are deployed at the most critical locations on the distribution network with respect to fault control and load switching.

LIS are considered to have a useful life of 20 years. Currently, Veridian operates nineteen 44kV LIS that were installed over the period 1979 to 1992, with a corresponding age range of 21 to 34 years, and seven which are 27 years or older. Under this project, Veridian intends to replace seven of the most critical of these switches, in order to avoid the significant reliability impacts which would follow the failure of these units. Replacement work was limited to only seven switches as a measured spending response to the need highlighted by the Asset Condition Assessment. Veridian is mindful of the total capital spending envelope that all its planned projects represent and smooths out spending plans wherever possible. Capital plans in the 2015 to 2018 period include investments in further overhead line switch replacement as flagged by the Asset Condition Assessment.

Project Description

Veridian will replace seven 44kV LIS that present the highest risk to reliability and system integrity, considering the age of the unit, the load carried, and the criticality of the fault interruption and switching functions.

These are motorized 3-phase gang switches, and will be replaced with SCADA-controlled units. In addition to providing SCADA capability at locations where it did not previously exist, the new units offer improved resistance to ice accumulation which can prevent proper switch operation, as well as the ability to be manually operated in the event of motor failure.

Evaluation Criteria

The trigger for this project is the need to replace critical equipment at end-of-life in order to avoid large reliability impacts in the event of failure. As noted above, 44kV equipment generally carries the highest loads and serves the largest number of customers; failures of equipment at this level can affect many thousands of customers. Even in the event where supply is not interrupted, the loss of switch function on these units can significantly impair Veridian’s ability to respond to outages elsewhere on the connected system and perform necessary switching operations.

This project is a high priority for Veridian because of the substantial reliability and operability impacts that would follow failure.

This project is not expected to materially affect safety, cyber-security, privacy, coordination, interoperability, economic development or the environment.

Category-Specific Information: System Renewal Projects

As noted above, the extent of the outages created by failure of equipment at this level on the distribution system is large. A significant advantage of replacing this equipment at end-of-life but prior to failure is the reduction of outage duration that is achieved when the equipment is replaced on a planned basis. Assuming that no other complicating factors are present which could prolong the outage, replacement on a planned basis eliminates from the outage duration the time required to assemble a crew and the necessary equipment and materials, and travel to the location of the failure.

The timing of this project is driven by the lifecycle of the equipment involved, which as noted above is at or beyond expected end-of-life.

Veridian does not anticipate that this project will have a material effect on O&M expenditures. The replacement equipment will continue to require inspection and maintenance similar to that of the equipment replaced.

Due to the important nature of these 44kV LISs in their ability to sectionalize feeders in the event of a fault and restore thousands of customers very quickly, Veridian will include SCADA operated motor functionality with all switches to be installed in 2014.

Project Cost Summary:	**$0.706 million gross**
Labour & Fleet	$0.112 million
Materials	$0.538 million
Contractor/Other	$0.056 million

Name of Project	Padmounted Transformers Replacement Program, various locations
Project Classification	System Renewal
Start Date	January 2014
In Service Date	December 2014
Capital Expenditure	$0.800 million gross

General Information

This system renewal project is to replace padmount transformers identified in the Asset Condition Assessment process as being in poor condition or at end of expected life.

As detailed in the Asset Condition Assessment Study Report, filed at Exhibit 2, Tab 3, Schedule 6, Attachment 1, the process of aging and deterioration of padmount transformers can involve both the housing and the foundation of the transformer, which if impaired through corrosion or shifting can lead to safety risks for the public and utility workers, as well as the internal components of the transformer including connections and transformer oil. In that case, an avoidable reliability consequence occurs if the unit is allowed to deteriorate to the point of failure.

Veridian has 8,722 padmounted transformers on its system, the large majority of which are in good or very good condition as indicated by their calculated Health Index. However, there are a limited number of units (134) in poor or very poor condition which Veridian plans to address over the near term, with 89 single-phase padmount and 3 three-phase padmount transformers planned for replacement in 2014.

Project Description

Veridian forecasts that the average cost to replace a single phase padmount will be $7,100 and that the average cost to replace a three phase padmount will be $55,000. Priority will be given to units that are at or past expected end of life and therefore pose a reliability risk. Units that pose a safety hazard will be addressed immediately under the reactive transformer and component replacement program.

Evaluation Criteria

The trigger for this project is the reduction of the reliability impacts of end-of-life padmounted transformers failing, by replacing those units on a planned basis. The program in 2014 represents a measured first response to the projected failure rates identified in the Asset Condition Study. As mentioned in other similar programs, Veridian will start equipment renewal programs that are mindful of the total capital spending envelope.

From a reliability perspective it is a medium to high priority for Veridian to replace equipment at end-of-life and with an elevated probability of failure on a planned basis, to avoid the incremental reliability consequences of having to replace the failed unit on a reactive basis. Veridian will nevertheless have to continue replacing padmount transformers reactively because not all padmount failures are predictable (for example, those caused by vehicle collisions).

As this project is generally going to replace units on a like-for-like basis, it is not expected to have a material impact on general levels of safety.

This project is not expected to have material effects on cyber-security, privacy, coordination, interoperability, economic development or the environment.

Category-Specific Information: System Renewal Projects

Veridian routinely inspects and maintains padmounted transformers to optimize their asset life and performance. However, since gradual deterioration is unavoidable and is sometimes accelerated for padmounted transformers due to the presence of corrosive road salts and other factors, this project targets those units which are now in poor condition and/or at end of expected life.

For an individual padmount transformer, the number of affected customers is usually approximately 10. However, when these units have to be replaced reactively, the outage time experienced by those customers is significantly longer than when the units are replaced on a planned basis. Veridian strives to avoid having to replace equipment reactively as a result of poor equipment condition, as contrasted with reactive replacement due to unpredictable causes such as vehicle collisions, storms, and lightning strikes.

Veridian does not expect that this project will have a material impact on O&M costs, since all padmount transformers are routinely inspected and maintained according to a regular program.

Project Cost Summary:	**$0.800 million gross**
Labour & Fleet	$0.250 million
Materials	$0.500 million
Contractor/Other	$0.050million

Name of Project	Padmounted Switchgear Replacement Program, Various Locations
Project Classification	System Renewal
Start Date	January 2014
In Service Date	December 2014
Capital Expenditure	$0.900 million gross

General Information

This system renewal project is to replace padmounted switchgear units that are currently in poor or very poor condition, as documented in the Kinetrics Asset Condition Assessment Report filed at Exhibit 2, Tab 3, Schedule 6, Attachment 1.

Padmount switchgear units are critical pieces of equipment on Veridian's system since they both conduct and control the flow of electricity on the distribution system. Switchgear units are used as connection points for cables and customers, to isolate faults on the distribution system, minimize the reliability impacts of faults, and perform planned switching to permit load transfers and maintenance operations.

Although the majority, (over 85%), of padmount switchgear units on Veridian's system are in good or very good condition, just over 8% (18 units) were found in the Asset Condition Assessment to be in poor or very poor condition.

In 2014 Veridian plans to replace eight of these units, prioritized on the basis of condition and criticality.

Project Description

Eight padmounted switchgear units will be replaced. The replacement units will be sealed tank, SF6 insulated design, in which no live parts are exposed to moisture and contamination. This design has both safety and durability benefits compared to legacy air insulated configurations.

Evaluation Criteria

The trigger for this project is the need to replace switchgear units which are aged and in poor or very poor condition prior to their failure in order to avoid significant reliability and safety risks.

The reliability impact of switchgear failures is variable depending on the load and number of customers served by the involved circuits. On higher voltage circuits such as 27.6kV, thousands of customers can be affected for several hours by a switchgear failure.

The safety impact of switchgear failures depends on the mode of failure. For example, fuse malfunctions can cause catastrophic failure which may in turn present a risk of severe personal injury and damage to nearby property or equipment. Even simple failures in the function of switchgear can present safety risks to utility personnel and can impede efforts to localize the impact of faults and power restoration.

Given the critical role of switchgear units in the distribution system, and the safety and reliability impacts of switchgear failures, this project is a high priority for Veridian.

The use of sealed tank, SF6 insulated switchgear units to replace live-front units in this project will provide incremental safety benefits relative to the use of live-front units.

This project is not expected to have material effects on cyber-security, privacy, coordination, interoperability, economic development or the environment.

Category-Specific Information: System Renewal Projects

Like many distributors, Veridian operates certain equipment with low failure impacts on a run-to-fail basis. While different switchgear units have different failure impacts depending on their rating, loading, and proximity to other equipment or personnel, generally Veridian strives to replace these units at end-of-life but prior to actual failure in order to avoid the potentially severe impacts of switchgear failure. As noted above, failures of switchgear units that are located at critical positions on the distribution system can affect thousands of customers for extended periods.

Veridian believes its plan for padmounted switchgear replacement in 2014 reflects a measured approach which mitigates the most pronounced risks at a reasonable cost.

Veridian does not anticipate that this project will have a material impact on O&M costs in 2014. Reduced CO2 cleaning costs are expected as the replacement units are added to the system population. The interval between cleaning is 3 years, so reductions are not expected until then. Replacement of air insulated switchgear to sealed tank, SF6 switchgear carries with it a premium of approximately $35,000 per unit. Veridian believes this to be a prudent expense due to the expected reduction in unit failures due to its sealed nature. This type of switchgear will eliminate contamination and tracking concerns that are the predominant cause of failure in Veridian's experience.

Project Cost Summary:	**$0.900 million gross**
Labour & Fleet	$0.250 million
Materials	$0.600 million
Contractor/Other	$0.050 million

Name of Project	Polemounted Transformers Replacement Program, various locations
Project Classification	System Renewal
Start Date	January 2014
In Service Date	December 2014
Capital Expenditure	$0.736 million gross

General Information

This system renewal project is to proactively replace polemounted transformers that are at end of life and are expected to fail in the near term.

Veridian has 7,661 polemounted transformers in service, ranging in age from 1 to over 70 years. These assets were assessed in the Asset Condition Assessment Study, filed at Exhibit 2, Tab 3, Schedule 6, Attachment 1. Based on sample age data from almost 50% of the population, over 90% were found to be in good or very good condition, but 2.8% or 105 units are in poor or very poor condition.

The mechanisms of polemounted transformer degradation and eventual failure are varied, as detailed in the Asset Condition Assessment Study report, and can include component deterioration as well as insulation breakdown. It is not generally considered economic to monitor the entire population of polemounted transformers for conditions that may result in failure prior to the expected end of life, since generally the consequences of failure are reasonably low and affect a small number of customers. Therefore for the general population replacement of failed transformers is done on a reactive basis.

However, on average it is more expensive to replace a polemounted transformer reactively than on a planned basis, since in many instances the failures occur at times when crews must be dispatched on an overtime basis, and may involve incidental damage to other equipment (for example, pole fires). In addition, the outage time involved in proactive replacement is materially lower than that for reactive replacement, since at a minimum (i.e., assuming the absence of other factors that could prolong reactive replacement), no crew travel time would contribute to outage duration when the work is done on a proactive basis.

Through this project Veridian seeks to reduce the costs of replacing polemounted transformers that are reasonably expected to fail over the near term, due to their age and accumulated deterioration, by replacing these units on a planned, or proactive basis. This program applies only to a small subset of the population where failure can be reasonably predicted over the near term without incurring the cost of direct monitoring and inspection, and not to the population in general where failures prior to expected end-of-life occur randomly.

Project Description

This project involves the planned replacement of selected polemounted transformers based on their age and inferred condition. Veridian plans to replace approximately 110 units in this category at an average cost of $6,700 per unit. Reactive replacement would cost approximately 30% more when completed on overtime. Based on the age of the units, Veridian believes that the foregone life of the units being replaced reactively is minimal.

Due to the small number of units replaced as part of this 2014 program, Veridian has not adjusted the reactive transformer and component replacement program. However, it is expected that over the longer term, reductions in the reactive spending program will be realized.

These units will generally be replaced on a like-for-like basis to current standards, except where location-specific conditions indicate that a difference is appropriate (for example, with respect to capacity). In certain instances dual-voltage units may be installed in areas where voltage conversion is anticipated, in order to avoid conversion costs in the future.

Evaluation Criteria

The trigger for this project is the need to replace polemounted transformers which are at end-of-life and are reasonably expected to fail over the near term at a cost that is lower than that which would be incurred if replacement were done on a reactive basis.

This project is a medium priority for Veridian, given that while savings are expected, this project is not obligatory from a statutory, reliability, or safety perspective.

This project is not expected to have material effects on safety, cyber-security, privacy, coordination, interoperability, economic development or the environment.

Category-Specific Information: System Renewal Projects

The assets to be replaced under this project are at or beyond their expected end-of-life.

The number of customers affected by individual polemounted transformer replacement is generally small, ranging from one to ten. However, Veridian expects that the outage time resulting from proactive replacement will be reduced materially compared to that for reactive replacement.

The timing of this project is driven by the demographics of the installed base of polemounted transformers. Veridian expects that after the initial backlog of units are replaced as indicated in the Asset Condition Assessment Study, a growing number of polemounted transformers will reach end-of-life each year in the future.

Veridian does not expect that this project will have a material impact on O&M costs, since polemounted transformer replacement costs are capitalized.

Project Cost Summary:	**$0.736 million gross**
Labour & Fleet	$0.250 million
Materials	$0.450 million
Contractor/Other	$0.036million

Name of Project	Primary Cable Rehabilitation Program, various locations
Project Classification	System Renewal
Start Date	January 2014
In Service Date	December 2014
Capital Expenditure	$1.0 million gross

General Information

This system renewal project is to rehabilitate primary underground cable. Veridian has approximately 1,595 km of underground cable on it system, with much of it direct buried and installed from the 1970's to the 1980's. At the time of installation cable materials and manufacturing techniques were considerably less advanced than exist today, and in many areas, for example south Ajax, Veridian has experienced accelerating rates of failure on these direct buried cables.

Veridian's underground cable assets were reviewed as part of the Asset Condition Assessment Study, the results of which are filed at Exhibit 2, Tab 3, Schedule 6, Attachment 1. The condition assessment for these assets was mainly driven by cable age, with adjustments for other factors such as cable type and manner of installation. Based on these results it is projected that failures will occur on approximately 80 km of underground cable in 2014.

Apart from direct mechanical damage due to earth movement or dig-ins, the principal mechanism of cable failure is breakdown of the insulating, or dielectric, properties of the cable insulation and sheathing. A major cause of this breakdown is 'water-treeing', a process in which moisture penetrates the insulation, degrading its dielectric strength and permitting dead-short faults to occur between the cable phases. These faults are difficult to predict because they are most likely to happen during transient events of high dielectric stress, when voltage surges occur due to lighting strikes, flashovers, or breaker operations.

Previous cable failures are indicative of the areas where existing cable has become problematic. Starting in 2014, Veridian will test 23 km of cable in these areas to determine its condition and the preferred method of rehabilitation. Testing costs have been included in O&M spending requirements documented elsewhere in this filing.

There are two options for cable rehabilitation, which are cable injection and cable replacement. Cable injection is a process in which a silicone-based fluid is injected under pressure into the cable. The fluid migrates under pressure along the length of the cable and restores the dielectric strength of the cable insulation and prevents further water treeing. However, not all varieties of cable material and construction permit injection. In addition, if the existing cable has failed many times and as a result has many splices, that block the passage of the silicone fluid, cable injection becomes uneconomic. Cable injection is also ineffective if the conductors of the cable have corroded to a significant degree. If the current condition of the cable as well as its original construction permit injection, that is the preferred method of cable rehabilitation because it is less costly than cable replacement and can substantially extend the life of the existing cable.

When cable injection is either technically infeasible or uneconomic, the remaining option is cable replacement. Cable replacement is more expensive than cable injection but does result in longer cable life than cable injection, and affords an opportunity to install the new cable in duct, which significantly reduces the cost and complexity of effecting repairs or alterations in the future, as well as eventual replacement at the cable's end of life.

Project Description

The results of the cable testing to be conducted in 2014 will determine areas which are candidates for cable injection and areas where cable replacement will be necessary. Veridian plans to inject 10 km of cable at a cost of $0.5 million, and to replace cable 0.8 km of three phase cable at a cost of $0.5 million. Veridian will target areas where underground cable has become most problematic.

Evaluation Criteria

The trigger for this project is the need to rehabilitate underground primary feeder cables in order to correct observed deterioration in those cables and worsening reliability performance. Underground cable failures cause a substantial portion (22% of all Veridian equipment faults and 34% of Ajax-area equipment faults in 2012) of equipment-related outages, and contribute significantly to SAIDI and SAIFI levels.

This project is a high priority for Veridian. For cables requiring replacement, reliability performance is already at poor levels and needs to be improved. Veridian also seeks to rehabilitate cables which are candidates for injection before that opportunity is lost due to further cable deterioration and the introduction of additional cable splices.

This project is not expected to have material effects on safety, cyber-security, privacy, coordination, interoperability, economic development or the environment.

Category-Specific Information: System Renewal Projects

As noted above, Veridian seeks to optimize cable lifecycle costs by performing injection in areas where it is still possible.

Primary cable failures affect variable numbers of customers and load depending on the location of the fault, which affects the number of downstream customers, and the load carried by the cable at the location of the fault. Cable faults at higher voltages such as 44kV can affect many thousands of customers for extended periods of several hours.

In the short term, the testing program which enables the rehabilitation of underground cable in the most economical fashion will increase O&M expenditures. Veridian does not expect a material reduction in O&M expenditures for underground cable repairs in the short term due to the limited scope of the cable rehabilitation program in 2014, but over time this program should avoid material underground cable repair costs, relative to what would occur in the absence of the program.

Project Cost Summary:	**$1.0 million gross**
Labour & Fleet	$0.3 million
Materials	$0.65 million
Contractor/Other	$0.05million

Name of Project	Reactive Pole Replacements
Project Classification	System Renewal
Start Date	January 2014
In Service Date	December 2014
Capital Expenditure	$0.752 million gross

General Information

Veridian routinely has to replace isolated poles or small groups of poles on a reactive basis to address conditions which require remediation. This can occur due to storm damage, poles becoming bent or out of plumb, fires, or the pole being found to be in unacceptable condition otherwise (for example, with respect to remaining strength) upon inspection. The expenditures reported for this project are for isolated reactive pole replacements; planned or programmatic pole replacements are reported under other projects.

Project Description

For 2014, Veridian expects it will reactively replace 94 poles, which is similar to the number of poles forecast to be replaced reactively in 2013. As illustrated in the table below, reactive pole replacement quantities have been generally increasing annually, leading to the slight increase in expected replacement quantities for 2013 and 2014. While 2014 marks the introduction of a new *proactive* pole replacement project, also found in this Schedule, Veridian expects to still replace poles reactively because of the factors mentioned in the General Information section above. The quantity of poles replaced in this manner in 2014 are not expected to be affected by the new proactive pole replacement program, as the relative quantity of new, proactively replaced poles, will be a small percentage of the 28,000 poles in Veridian's system. Over the longer term, it is anticipated that the proactive pole replacement program, when guided by pole testing data, will result in a reduction of poles requiring emergency/reactive replacement through the elimination of weakened or otherwise compromised poles. A combination of 44kV and distribution poles will require reactive replacement in 2014, but on average they are expected to cost $8,000. Under reactive replacement, poles are generally replaced like-for-like, including costs for switching, cross arms and hardware used to frame the poles. While older poles may not have been built with the clearances currently required, Veridian attempts to make any improvements possible during the replacement of defective poles.

Pole Replacement Experience 2010-2013

	2010 (actual)	2011 (actual)	2012 (actual)	2013 (as of Sept 30)
44kV Poles	8	7	7	7
Distribution Poles	67	45	74	32
Total Cost ($M)	$0.568	$0.611	$1.129	$0.305

Evaluation Criteria

The trigger for reactive pole replacement is the immediate need to replace the pole to rectify intolerable conditions and restore service and/or safety conditions to acceptable levels. In most instances reactive pole replacement is required due to the pole having fallen or having been severely damaged due to wind, tree falls, vehicle collisions, or similar factors. In these instances immediate action is required on Veridian’s part. Less often it becomes apparent by inspection that a pole has fallen into unacceptable condition, for example due to the action of rot, insects or wildlife, and requires urgent action to rectify.

Reactive pole replacement is a very high priority for Veridian because unsound or severely damaged poles either directly interrupt the supply of electricity to customers or present unacceptable risks to safety and reliability.

While alternatives would be available in most instances of planned pole replacement, it is Veridian's practice in cases of reactive pole replacement to attempt, wherever possible, to make clearance improvements to poles replaced in older areas that may not be consistent with current construction standards.

As noted above, reactive pole replacement is required to rectify an unsafe pole condition. The reactively replaced pole may offer an improved level of safety if current construction standards are possible in the construction of the new pole versus a legacy pole at that location. This project is not expected to have material effects on cyber-security, privacy, co-ordination, interoperability, economic development, or the environment.

Category-Specific Information: System Renewal Projects

As indicated above, poles that require reactive replacement have, for a variety of reasons, reached an intolerable condition with respect to safety and/or ability to provide service, and consequently Veridian has virtually no discretion concerning their replacement.

It is not possible to meaningfully generalize about the number of customers affected by this project, and across individual instances the number of customers affected, the magnitude of the safety risk, and the duration of any associated outage can vary widely.

This project is defined overall on an annual basis and it is expected that reactive pole replacements will occur throughout the year. Any individual job will generally need to be done immediately, or at a minimum very urgently, in order to restore power or resolve a threat to safety.

Where it is tolerable to do so, Veridian seeks to minimize the cost of reactive pole replacement by scheduling the work during regular daytime hours. However, in many instances the situation must be addressed immediately regardless of whether overtime is required.

Project Cost Summary:	**$0.752 million gross**
Labour & Fleet	$0.620 million
Material	$0.094 million
Contractor/Other	$0.038 million

Name of Project	Reactive Transformer and Component Replacements
Project Classification	System Renewal
Start Date	January 2014
In Service Date	December 2014
Capital Expenditure	$0.9 million gross

General Information

Veridian routinely has to replace transformers and associated components on a reactive basis when those transformers fail unpredictably or present unacceptable conditions upon inspection. This can occur due to vehicle collisions, asset deterioration, overloading, and other factors.

Immediate reactive transformer replacement is necessary when a transformer fails, thereby creating an outage, or when it is suddenly and severely damaged, as might occur as a result of a vehicle collision. In those circumstances even if the transformer continues to function electrically, its housing will have been compromised introducing an unacceptable safety risk.

In other cases the condition of the transformer may require urgent, but not immediate replacement of the transformer.

This project reports expenditures on reactive distribution (i.e., padmount and polemount) transformer replacement. Expenditures on planned replacement of distribution and substation transformers is presented under other projects documented in this application.

Project Description

In 2014, Veridian expects to reactively replace 84 padmount transformers and 32 polemount transformers, for a total of 116. This forecast is based on recent history and an expectation that replacement quantities will increase slightly due to the increasing average age of the transformer population. In addition, associated equipment such as lightning arrestors and animal protectors will be replaced where necessary.

Evaluation Criteria

The trigger for any individual replacement is the (usually sudden) failure of the equipment, either from the perspective of electrical distribution or safety, or both. Neither of these failures is tolerable.

Reactive transformer and component replacement is usually a very high priority for Veridian, and is always a high priority at a minimum, due to the reliability and potentially serious safety consequences of the failure of this equipment.

Although alternatives may exist for transformer replacements on a planned basis, reactive transformer replacement is typically on a like-for-like basis, with the exception that Veridian seeks to install dual voltage transformers in areas which are candidates for voltage conversion. While it is often necessary to replace transformers reactively to correct a safety risk, the level of safety that is restored after the replacement is made is not expected to be materially affected by this project.

This project is not expected to have material effects on cyber-security, privacy, co-ordination, interoperability, economic development, or the environment.

Category-Specific Information: System Renewal Projects

As indicated above, distribution transformers and associated components that require reactive replacement have, for a variety of reasons, reached an intolerable condition with respect to safety and/or ability to provide service, and consequently Veridian has virtually no discretion concerning their replacement.

It is not possible to meaningfully generalize about the number of customers affected by this project, and across individual instances the number of customers affected, the magnitude of the safety risk, and the duration of any associated outage can vary widely. However, in individual cases the number of customers affected by the failure of a distribution transformer is usually in the range of one to ten.

This project is defined overall on an annual basis and it is expected that reactive pole replacements will occur throughout the year. Any individual job will generally need to be done immediately, or at a minimum very urgently, in order to restore power or resolve a threat to safety.

Where it is tolerable to do so, Veridian seeks to minimize the cost of reactive transformer and component replacement by scheduling the work during regular daytime hours. However, in many instances the situation must be addressed immediately regardless of whether overtime is required.

Project Cost Summary:	**$0.900 million gross**
Labour & Fleet	$0.500 million
Material	$0.450 million
Contractor/Other	$0.00 million

Name of Project	Substation Breakers Replacement, Toronto Substation
Project Classification	System Renewal
Start Date	September 2014
In Service Date	November 2014
Capital Expenditure	$0.600 million gross

General Information

This system renewal project is for the replacement of three circuit breakers at the Toronto substation in Newcastle which have been determined through the Asset Condition Assessment process to be in poor condition warranting replacement. In addition, the feeder egress cables connected to the breakers will be replaced to resolve a capacity constraint created by the inadequate thermal capacity of the existing egress cables.

The Kinetrics Asset Condition Assessment Study, filed at Exhibit 2, Tab 3, Schedule 6, Attachment 1, identified seven substation circuit breakers as being in poor or very poor condition warranting replacement, as part of an ongoing program managed asset renewal. Veridian concurs with the Kinetrics recommendations concerning substation breakers. Due to the magnitude of the outage that would follow the failure of substation circuit breakers, these assets are not run to failure but are replaced proactively when at end-of-life or otherwise in poor condition, but prior to failure. Of the seven identified breakers, six are at the Newcastle substations, with three to be replaced as part of the Wilmot substation upgrade project in 2013. The other three, including one breaker in very poor condition, are located at the Toronto substation. Subsequent to the Wilmot substation upgrade project in 2013, it will be possible for Veridian to take the Toronto substation out of service for maintenance and this planned upgrade is during the fall shoulder period when demand is at a seasonal low.

Project Description

This project will involve the removal and replacement of the three existing 13.8kV circuit breakers together with the associated feeder egress cables. At present, the feeder egress cables are 500 MCM cable, and their thermal capacity limits the load that can be served out of the station to 6 MVA, below the existing transformer capacity of 10 MVA. These egress cables will be replaced with 1000 MCM cable to remove this capacity constraint.

The existing circuit breakers are of the gas insulated type. They had been installed as part of an upgrade from fuse protection approximately 20 years ago. Experience with these now obsolete breakers has been poor due to multiple mechanical issues internal to the breaker. Repair success has been generally low, with problems being seen even on recently serviced breakers. The original equipment manufacturer no longer has access to original parts and is fabricating them locally. Breakers at Toronto station are the same type as those at the old Wilmot station. These breakers were in part responsible for the upgrade of that station. Similar to the Wilmot substation design, these will be replaced with 3 units of the padmounted recloser type, which offer dead front operation, SF6 insulation for safer, more reliable operation and a lower purchase cost than switchgear mounted breakers. Veridian has similar installations in 3 other stations.

The cost to replace the circuit breakers and the feeder cables are shown in Table 1 below.

Table 1: Circuit Breaker and Feeder Egress Cable Costs

Item	Cost ($ millions)
Circuit Breakers	$0.160
Feeder Cables	$0.440
Total	$0.600

Evaluation Criteria

The main trigger for this project is the need to replace existing circuit breakers in poor or very poor condition prior to their failure, which failure would cause a prolonged equipment outage and could damage adjacent equipment, depending on the mode of failure. An additional objective is to remove an existing capacity constraint imposed by the undersized feeder egress cables, which will increase the effective capacity of the substation and make full use of the existing transformer capacity.

This is a high priority for Veridian given the condition of the existing circuit breakers and the risk of a possibly catastrophic failure and prolonged equipment outage.

A safety risk is created by the poor condition of the existing circuit breakers from potential misoperation and failure. Replacement reclosers will offer staff a safety improvement through their dead front operation.

This project is not expected to have material effects on cyber-security, privacy, coordination, interoperability, economic development, or the environment.

Category-Specific Information: System Renewal Projects

As noted above, the poor condition of these circuit breakers elevates the risk of their failure, either simply or catastrophically. Were a failure to occur at a time of heavy loading, Veridian estimates that 1500 commercial and residential customers would experience an outage. Veridian and its customers would then be in a position of significantly elevated risk because a failure at the remaining Wilmot substation could not be compensated by load transfers to the Toronto substation.

For the reasons noted above, it is a high priority for Veridian to replace the subject equipment on a planned basis at a time when the risks of first contingency operation are at their lowest. Given the needs for both elements of this work, it would be disadvantageous to conduct the work at two separate times.

Veridian does not expect there to be a material effect on O&M costs as a result of this project.

Project Cost Summary:	**$0.600 million gross**
Labour & Fleet	$0.350 million
Materials	$0.225 million
Contractor/Other	$0.025million

Name of Project	Substations Transformer Replacement, Greenwood Substation
Project Classification	System Renewal
Start Date	June 2014
In Service Date	October 2014
Capital Expenditure	$0.713 million gross

General Information

This system renewal project is to decommission an existing 5MVA, 44kV to 8.32kV substation transformer in poor condition at Greenwood substation, and convert the supplies to the served area from 44kV to 27.6kV by installing three 1.5MVA, 27.6kV to 8.32kV padmount transformers at various locations.

The effect of the decommissioning and supply voltage conversion will be to increase security of supply to this area of Pickering and make incremental 44kV supply available to areas where it is required.

At present, approximately 600 customers in northeast Pickering are supplied out of the Greenwood substation. The substation itself is supplied by a radial feed without backup from the 44kV system, which is at the limit of its capacity in the Pickering and Ajax areas. As documented in the Kinectrics Asset Condition Assessment (ACA) report (filed at Exhibit 2, Tab 3, Schedule 6, Attachment 1), the Greenwood substation transformer is in poor condition and is identified as a priority for replacement. Were there to be a serious failure on the 44kV radial feed or on the substation transformer, no backup supply is available and customers would experience a prolonged outage of up to 24 hours.

This project will transfer the subject load to be supplied to the 27.6kV system, which has adequate capacity and which can be switched to alternate sources in the event of faults to minimize the outage impact. In addition to making backup supply available, this will free needed 44kV capacity for use in other areas where there are no alternatives to 44kV supply.

Project Description

The substation at Greenwood substation will be decommissioned. In its place Veridian will install three 1.5 MVA, 27.6 kV to 8.32 kV padmount transformers with fuse protection at various locations in the area to make switchable and redundant supplies available.

Evaluation Criteria

The trigger for this project is the need to replace the poor-condition transformer at Greenwood substation, identified in the ACA as a priority for replacement. The probability of failure for this unit is elevated, and as noted above, the consequences of failure under the present supply configuration are more pronounced than average for Veridian’s urban customers. The supply reconfiguration meets the additional goals of improving security of supply and freeing 44kV capacity for use elsewhere where no alternatives are available.

This project is a high priority for Veridian because of the poor condition of the transformer and elevated consequences of failure.

While it would be possible to simply replace the 44kV to 8.32kV transformer, that alternative does not provide the benefits afforded by the supply voltage conversion nor the advantage of enabling system backup from nearby Green River station that is also 27.6kV to 8.32kV.

This project is not expected to have material effects on safety, cyber-security, privacy, coordination, interoperability, economic development or the environment.

Category-Specific Information: System Renewal Projects

The transformer to be replaced was installed in 1973, is in poor condition, and is at or near end of life. Because of the substantial consequences of a substation transformer failure, especially in these circumstances where backup supply is not readily available, Veridian does not take the approach of running those assets to failure, but rather replaces them at end of life prior to their failure. Refurbishment was considered as an alternative. Though it was possible to do, a replacement transformer would need to be sourced and temporarily replace the existing transformer while it was being refurbished, and it would not improve the system configuration issues as noted above. In the end, it was decided that refurbishment was not the best option.

As noted above, a failure of this transformer would affect approximately 800 customers for a prolonged period.

Veridian does not expect that this project will have a material effect on O&M expenditures.

Project Cost Summary:	**$0.713 million gross**
Labour & Fleet	$0.350 million
Materials	$0.300 million
Contractor/Other	$0.063 million

Name of Project	Substation Transformer Replacement and Component Upgrades - Fairport SS
Project Classification	System Renewal
Start Date	April 2014
In Service Date	November 2014
Capital Expenditure	$2.435 million gross

General Information

This system renewal project is to replace one substation transformer in poor condition in Pickering with a larger transformer, and to perform associated system service upgrade work at the same station for the purpose of expanding outgoing feeder capacity and improving reliability. This work is being completed in two phases as both transformers at the Fairport substation have been 'flagged for action' by the Asset Condition Assessment.

The principal component of this project is the transformer replacement. The transformer in question has been identified in the Kinectrics ACA (filed at Exhibit 2, Tab 3, Schedule 6, Attachment 1) as being both in poor condition and exhibiting an elevated criticality based on the difficulty to be able to provide system backup for its load in the event of a failure, the lack of an oil containment system and the use of a fuse as the transformer's primary protection. These factors combined with the need to do other work in this area in Pickering to relieve current and expected capacity constraints, together with consequential work in the station on associated equipment, led Veridian to prioritize this substation transformer replacement work.

Project Description

This project involves the replacement one of the two existing 10/13/16 MVA, 44kV to 13.8kV transformers at Fairport substation, which is in poor condition, with a larger 15/20/25 MVA transformer of the same voltages. This is being undertaken both to correct the poor transformer condition and to provide needed additional capacity in the area.

In order to relieve other capacity constraints in this area of Pickering, Veridian plans to replace three existing 13.8kV 500 MCM feeders with three 28kV1000 MCM feeders, operating at 13.8kV, to be fed by the new transformer. The replacement of the feeders necessitates the removal of three existing 13.8kV reclosers mounted on overhead structure and the installation of three new padmounted 27.6kV rated reclosers., the installation of 800 metres of feeder duct banks, and the installation of 2480 metres of 1000 MCM cable.

The breakdown of costs among these three project components is given below in Table 1.

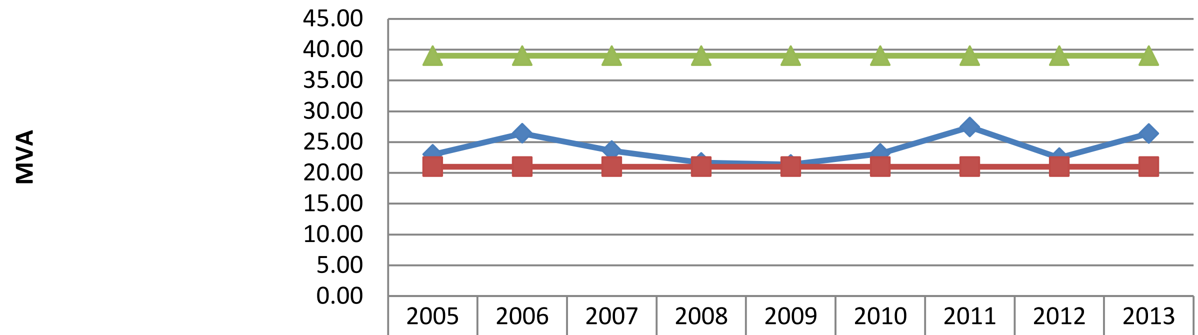
Item	Cost ($ millions)
Transformer replacement, Civil Work, Oil Containment, Transrupter, 44kV Pole, Substation Building, Switches	$1.583
Feeder replacement	$0.419
Recloser replacement, with associated Relays	$0.433

Evaluation Criteria

The main trigger for this project is the need to replace the substation transformer identified as being in poor condition through the ACA. This transformer is 39 years old and contains rectangular windings. Veridian has experienced a number of transformer failures with this winding shape as the geometry of the winding is significantly stressed during a nearby fault.

During the fault the winding will want to take on a round shape. Over time the stresses in the winding will accumulate and lead to a failure. Failures of this type have occurred at Town Centre, Monarch and Sidney substations in the last five years. As documented in the ACA report, the consequences of substation transformer failures can be severe, both in terms of the magnitude and duration of the resulting outage, and in terms of possible damage to surrounding equipment and the environment, depending on mode of failure. Catastrophic failure can lead to dangerous fires and potential release of transformer oil. The Fairport substation does not have an oil containment system, so the potential for oil release is elevated. Fairport substation is located within the confines of the Hydro One Cherrywood TS and adjacent to Pine Creek in Pickering. Cherrywood TS experienced a significant oil release from a failed transformer in 2003 and Hydro One expects that this upgrade of Fairport substation would be used to eliminate this concern in Veridian's station. The area served by the Fairport substation is also subject to capacity constraints in a context of growing load. This substation in part, feeds the Highway #2 area from Fairport Road to the Pickering Town Centre and this area is being redeveloped over the next twenty years. The load will be growing in this area as it forms part of the City of Pickering's Downtown Intensification Plan. The Fairport Substation is part of the plan to supply this growing area Figure 1 below depicts historical and forecast load in the area versus existing feeder capacity.

Figure 1: Load versus Feeder Capacity



	2005	2006	2007	2008	2009	2010	2011	2012	2013
Fairport SS Total Peak Load(MVA)	22.99	26.41	23.60	21.68	21.35	23.14	27.43	22.46	26.37
Feeder Capacity with Three Feeders(500 MCM) MVA	21	21	21	21	21	21	21	21	21
Feeder Capacity with three feeders (1000 MCM) MVA	39	39	39	39	39	39	39	39	39

The installation of the three new feeders together with the necessary reclosers will increase the overall feeder planning capacity (ie loss of one of the four feeders egressing from the station) available from Fairport substation from 21MVA to 39MVA, and will improve Veridian's ability to meet new load in the area, respond to outages, and manage routine switching operations for maintenance purposes, all of which are beneficial for the customers served from that substation.

These investments are high priorities for Veridian because of the significant reliability and other risks created by the poor condition of the transformer and the need to expand available capacity out of the substation.

Because of the significant interdependencies among the equipment at and emanating from the substation, it is advantageous and cost effective for Veridian to integrate this work into one project rather than fragmenting the different components. The latter approach would leave new transformer capacity unused for a period of time and would introduce unnecessary costs and operational disruptions.

A safety benefit will be achieved by the replacement of the transformer that is in poor condition.

Veridian does not expect that this project will have material effects on cyber-security, privacy, coordination, interoperability.

Veridian does anticipate that this project will have positive economic development and environment benefits by improving Veridian's ability to meet load reliably and by reducing the risk of catastrophic transformer failure, which has very negative environmental impacts.

Category-Specific Information: System Renewal Projects

Veridian estimates that 2,500 commercial and residential customers would be affected by a failure of the subject transformer. The magnitude and duration of the outage would depend on Veridian's ability at that time to meet load through switching operations and the use of a portable transformer, if possible.

As noted above, while the basic timing of this project is driven by the need to replace the transformer in poor condition, the inclusion of the other work is advantageous for the reasons noted there.

Veridian does not anticipate a material effect on O&M costs as a result of this project.

Project Cost Summary:	**$2.435 million gross**
Labour & Fleet	$0.200 million
Materials	$1.900 million
Contractor/Other	$0.335 million

Name of Project	Substation Transformer Spare Replenishment
Project Classification	System Renewal
Start Date	February 2014
In Service Date	July 2014
Capital Expenditure	$0.9 million gross

General Information

This system renewal project is to provide a spare 15/20/25 MVA, 44kV to 13.8kV substation transformer to enable Veridian to replace a failed unit in a timely manner should there be a failure of a similar transformer on Veridian's system. Due to a transformer failure at Veridian's Town Centre substation that required installation of the only large capacity 13.8kV system spare transformer from inventory, Veridian does not have such a spare, and would therefore be forced into a prolonged period of first contingency operation should a failure occur.

Currently much of the Ajax-Pickering and Bowmanville areas are served through 13.8kV distribution supplied at 44kV. Substations in those areas typically have at least one 10-15MVA transformer in operation. Veridian's capacity planning criteria are that in a given area, if one of the highest rated substation transformer fails, other transformers in the connected area have sufficient capacity to accept the load transferred from the failed transformer. However, that event would place Veridian in a condition of first contingency operation. Under those conditions, were a second transformer (or other material piece of equipment) to fail, no spare capacity would be available to accept load and a prolonged outage would result until the fastest repair could be effected. Depending on the specific circumstances, it could be days or weeks before the replacement equipment could be sourced and installed. Because of these extremely severe consequences, Veridian strives at all times to minimize the duration of first contingency operation.

Project Description

This project involves the purchase of a spare 15/20/25MVA, 44kV to 13.8kV substation transformer to be available for installation in the event of a failure of a similar transformer on Veridian's system. The spare transformer would be suitable for installation at twelve of Veridian's substations in Ajax, Pickering and Bowmanville. Delivery on these transformers takes anywhere from 5-12 months.

Evaluation Criteria

The trigger for this project is to eliminate the risk that Veridian customers would be subject to an extremely long outage because of the unavailability of spare replacement equipment.

This project is a very high priority for Veridian because of the severe consequences involved.

This project is not expected to have material effects on safety, cyber-security, privacy, coordination, interoperability, economic development or the environment as these items are normally considered. However, a prolonged power outage lasting days or weeks has severely disruptive consequences for economic activity, and can have negative consequences for public safety and the environment to the extent that normal infrastructure is not functioning properly.

Category-Specific Information. System Renewal Projects

This project is not directly related to the condition of equipment presently operating on Veridian's system. It is characteristic of electricity distribution equipment that it can fail unpredictably due to a variety of causes regardless of its apparent condition at any point in time.

As noted above, the consequences of a failure of a major piece of equipment on Veridian's system that is not remediable for days or weeks are severe.

Veridian will follow its standard procurement processes in order to minimize the acquisition cost of the new transformer.

Project Cost Summary:	**$0.9 million gross**
Labour & Fleet	$0.0 million
Materials	$0.9 million
Contractor/Other	$0.0 million

Name of Project	Wood Pole Replacement Program, various locations
Project Classification	System Renewal
Start Date	January 2014
In Service Date	December 2014
Capital Expenditure	$2.042 million gross

General Information

This system renewal project is to proactively replace wood poles that have reached end of life or are otherwise in poor condition, prior to their failure. Wood poles were included in the Kinetrics Asset Condition Assessment study (filed at Exhibit 2, Tab 3, Schedule 6, Attachment 1) and based on the information available at this time Kinetrics projected that 528 poles would likely fail on Veridian's system in 2014. However, that result is based on extrapolation of data from a relatively small sample.

Veridian acknowledges the need to obtain more precise and comprehensive information on its population of approximately 28,000 poles, and since 2012 has undertaken a program of pole testing that it expects to complete in 2016. Three thousand poles will have been tested by the end of 2013, and Veridian plans to test a further 8,350 poles per year in 2014 through 2016.

In view of the imminent acquisition of more detailed information on pole condition, and competing capital needs on its system, Veridian determined that a reasonable approach for the 2014 program of proactive pole replacement would be to replace 250 poles, at an average cost of approximately $8,000 per pole.

The proactive pole replacement program differs from the reactive program in that the proactive program focuses on replacement of poles determined to be in poor condition prior to their actual failure. The reactive program is to replace poles that may immediately prior to failure have been in any condition, including very good condition, but which fail as a result of numerous causes apart from asset degradation.

Over time the proactive pole replacement will reduce, but not eliminate the number of poles replaced reactively, since reactive replacement can become necessary for reasons other than asset degradation. However, Veridian does not expect there to be a material impact on its reactive program in the first years of the proactive program.

Project Description

This proactive project will involve the replacement of 250 poles known to be in poor condition or at the end of expected life. The poles to be replaced will be prioritized based largely on age and condition, with consideration of other operational factors, such as pole criticality and the availability of resources in the area, also included.

Evaluation Criteria

The trigger for this project is the need to replace poles that present a high risk of failure prior to their actual failure. By doing so, Veridian will significantly mitigate the risk of unplanned outages and safety hazards to both the public and its crews.

This project is a medium-high priority for Veridian, given the benefits in terms of risk reduction that it will achieve.

This project is not expected to have material effects on existing levels of cyber-security, privacy, coordination, interoperability, economic development, or the environment.

Category-Specific Information: System Renewal Projects

The avoided outage impact achieved by the replacement of individual poles or small groups of poles varies widely according to the number of circuits carried by the pole, the voltage of those circuits, and the existence of other system control equipment on the pole. The number of customers affected can range up to the tens of thousands.

As noted above, Veridian has chosen to reduce the proposed number of poles to be replaced relative to that indicated by the Asset Condition Assessment pending the development of further information on pole condition, and intends to spread this expenditure over many years, balancing the benefits obtained from the program against the corresponding costs.

Veridian does not anticipate a significant impact on O&M costs resulting directly from this project, although increased expenditures will be necessary for the related pole testing program.

Under this program, replacement poles will be built to current standards, wherever possible. Efforts will be made to improve legacy pole framing to new poles with improved clearances.

Project Cost Summary:	**$2.042 million gross**
Labour & Fleet	$1.0 million
Materials	$0.9 million
Contractor/Other	$0.142 million

Material Investments - 2013 and 2014 - System Service Category

Name of Project	Pickering Beach Substation Upgrade
Project Classification	System Service
Start Date	January 2013
In Service Date	June 2013
Capital Expenditure	$2.12 million gross

Overview

This system service project was required to add needed capacity to the south Ajax area, which was subject to rotating blackouts in 2012 on a peak day. The added capacity will accommodate anticipated peak day loading in Ajax and also provide backup capacity for the north Ajax area.

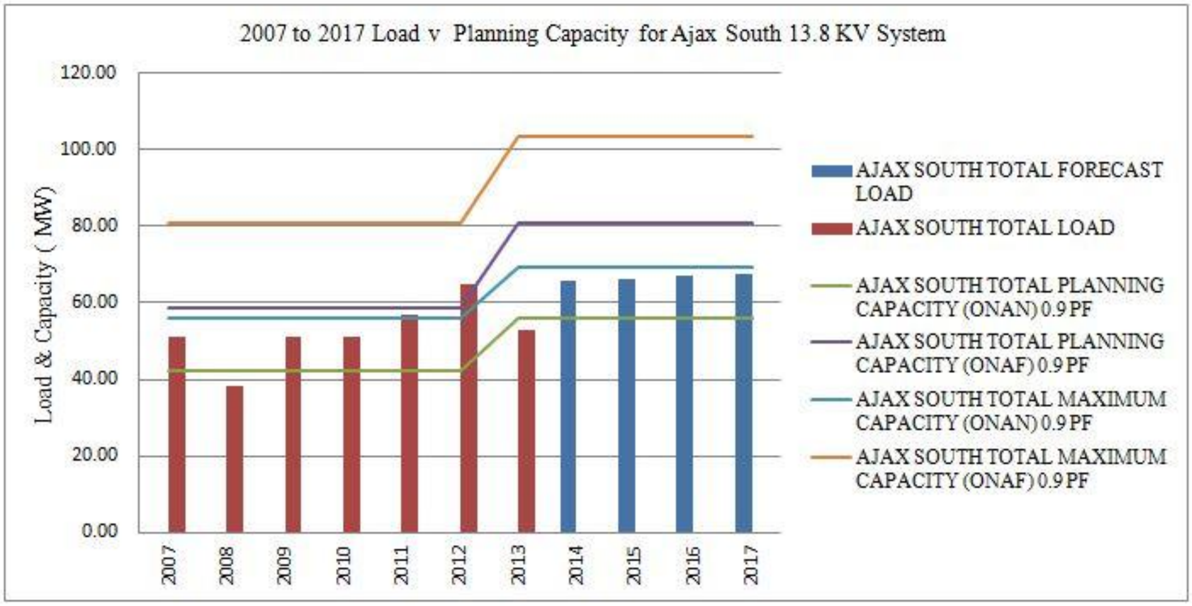
The Pickering Beach substation is one of four substations that serve the south Ajax area. The south Ajax area has for many years exhibited poorer than average reliability due to underground feeder cable deterioration. In July 2012 during a peak period, a quantity of equipment supplying the Ajax/Pickering area was out of service. These included a 44kV feeder out of service for planned construction, a full transformer and 4 feeders at Applecroft substation was out of service due to a switchgear failure, as was a 13.8kV feeder out of Fairport station. As a result of equipment unavailability elsewhere in the Ajax area, the Pickering Beach substation was already heavily loaded, and that loading was exacerbated by peak demands due to hot weather. Consequently, Veridian was compelled to introduce rotating outages on the load served by Pickering Beach substation to avoid permanent damage to the equipment there.

In order to resolve capacity-related reliability shortfalls in the south Ajax area, Veridian increased capacity at Pickering Beach substation by adding a transformer and associated equipment.

Project Description

This project involved the installation of a 44kV to 13.8kV 15/20/25 MVA transformer on a vacant transformer pad at the Pickering Beach substation as well as associated equipment including a 44kV transformer protection device known as a Transrupter. This substation was always planned as a dual transformer substation with the timing of the 2nd unit to be installed on a when necessary basis. This new equipment added 15 MVA of capacity under normal operating conditions and provides a maximum of 25 MVA under peak load conditions. In addition, Veridian will install in late 2013 an oil containment system at this substation to provide environmental protection as standard part of a normal substation upgrade.

This will resolve the capacity shortage under standard planning assumptions of the largest transformer in an inter-connected area being out of service, with the remaining transformers (and associated equipment) being able to sustain the extra load transferred to that equipment. Figure 1 below depicts historical and forecast peak loading in the south Ajax area compared to first contingency capacity available, in that area. The increase in the Ajax South capacity lines reflects the addition of the new transformer into that area.



Veridian's standard planning practice, as described in more detail at Exhibit 2, Tab 3, Schedule 8 reference for generic write up of system planning assumptions, is to use natural air (ONAN) cooling ratings in capacity determinations. Veridian examined other alternatives for substation upgrades to resolve the under-capacity issue in south Ajax. Of the other three substations serving the area, none were built with future expansion capabilities, whereas Pickering Beach substation was, and had an available and adequate spare transformer pad already in place. Feeder egress from the substation was easier and less costly than from the other area substations, and additional capacity installed at Pickering Beach could be made fully available to the south and north Ajax areas through interconnected feeders. In order to connect the new transformer to the local system, a feeder construction project was completed that brought 1 x 44kV feeder to supply the substation as well as 2 x 13.8kV feeders to supply the local area. The 350m long project installed 10 poles and enabled a second 44kV circuit to be brought to Pickering Beach station, giving an independent supply that can be used to feed both transformers at the station should there be a fault on the original 44kV supply. Alternately, the original supply could be used to supply both transformers should there be a fault on the new supply. The costs for the feeder construction totaled $310,000.

Project Cost Summary:	**$2.12 million gross**
Labour & Fleet	$0.31 million
Material	$1.75 million
Contractor/Other	$0.06 million

Name of Project	SCADA System Replacement / Upgrade
Project Classification	System Service
Start Date	January 2013
In Service Date	December 2013
Capital Expenditure	$0.601 million gross

Overview

This project includes the replacement and upgrade of the existing Telvent System Control and Data Acquisition (SCADA) system with a new and modern version of the Telvent SCADA system. The total budgeted cost for the project is $601,000 and the on-going OM&A costs are forecast to be $27,925 annually, representing an incremental OM&A increase of approximately $7,000 per annum over the existing SCADA system.

The SCADA system replacement / upgrade is necessary as the existing Telvent SCADA system at Veridian was purchased in 2001 and is at end of life. Replacement parts are becoming difficult to source from reputable suppliers and vendor support for the software is diminishing. The functionality of the existing SCADA system is very basic and not suited for the future requirements to operate a smarter distribution system. The new SCADA system will ensure Veridian has a reliable SCADA system for the monitoring and control of its electric distribution system and a platform upon which advancements in distribution system automation and smart grid can be leveraged.

Project Description

In 2001, Veridian purchased a Telvent SCADA system to monitor and control its electric distribution system. The SCADA system performed very well and provided excellent value to Veridian and its customers over the past 12 years.

During 2011 and 2012, it became apparent that the software and hardware for the SCADA system were becoming obsolete and it was difficult to source replacement parts for the hardware in particular. It also became apparent that smart grid requirements were driving the need for additional distribution automation functionality and capability for SCADA systems, particularly given Veridian's diverse geographic territory.

During the first 6 months of 2013, Veridian prepared system specifications for the new SCADA system, issued a request for proposals based on the specifications, completed a vendor selection process and selected a vendor in accordance with procurement policy requirements. A purchase order was issued in July, 2013 for a new Telvent SCADA system.

One factor in the evaluation of vendors was a risk assessment on the ability to successfully complete the project on-time and on-budget. Veridian determined that the lowest risk associated with completing the project in a satisfactory manner would be achieved through the selection of a Telvent product. Communication protocols already exist between the Telvent SCADA system and field devices, and the new Telvent product is designed to recognize those protocols utilized in earlier versions of its software, significantly reducing the risk and commissioning costs associated with the new system.

The primary driver of the project is equipment reliability. As previously mentioned, the age of the system and the platform upon which the hardware and software operate is such that replacement parts and support is difficult to source. Interruption to the operation of the SCADA system has a negative impact on Veridian and its customers. The SCADA system is utilized to detect distribution system anomalies, particularly with regards to power outages, the dispatching of crews to the affected area and to perform automated switching from the System Control centre (SCC). Without the SCADA system, outages are longer in duration and affect more customers, which contribute to a loss in reliability and customer satisfaction. Premature loss of distribution system equipment, due to overloading for example, can also be attributed to the loss of the SCADA system.

Another driver is the requirement to meet customer expectations with regards to reliability. Veridian intends to improve its distribution system reliability through automation. A more automated distribution system allows, for example, the ability to utilize self-healing networks. A self-healing network can automatically detect a system fault, isolate the fault and re-supply as many affected customers as possible within a very short-time frame with no human operator intervention, improving reliability and value for customers. The new SCADA system provides the platform upon which Veridian can continue to build its capabilities with distribution system automation and enable this functionality.

Another further significant driver is worker and public safety. Having visibility and control of the distribution system from the SCC allows an increase in the level of security and safety to both Veridian's workforce and members of the public through the continuous monitoring of system status and the ability to dispatch crews and/or operate the system remotely in the event of equipment failures and power outages.

Operating the existing SCADA system in a "run-to-failure" mode would introduce significant risk to distribution system reliability, safety, customer satisfaction and the efficient dispatch of work crews.

Veridian believes the new Telvent SCADA system to be one of the most cyber-secure systems available on the market today and was an important consideration.. The new system will adhere to corporate guidelines and external regulations such as the North American Electric Reliability Corporation – Critical Infrastructure Protection (NERC CIP). Any data and access through the internet will be authenticated using encryption and user account authentication, such as the x.509 standard certificates. This, along with the server configuration proposed by Telvent and the secure internet tunnel currently employed by Veridian, will ensure the highest level of cyber-security and privacy protection available today.

An alternative to an outright purchase was considered. A hosted solution with another Ontario LDC was considered, whereby Veridian would continue to operate its distribution system through its central control room; however the centrally located computerized SCADA system would be owned and maintained by the other Ontario LDC at their facility. This alternative was rejected due to technical issues with the communication system, which would be cost prohibitive to overcome.

Project Cost Summary:	**$0.601 million gross**
Labour & Fleet	$0.089 million
Material	$0.512 million
Contractor/Other	$0.0 million

Name of Project	Voltage Conversion – 4.16kV First Street (First x James), Gravenhurst
Project Classification	System Service
Start Date	October 2013
In Service Date	December 2014
Capital Expenditure	2013 \$0.450 million 2014 \$0.432 million Total \$0.882 million

General Information

This system service voltage conversion project is part of a planned, multi-year initiative to add needed capacity, reduce significant risks to reliability, and reduces losses in the Gravenhurst area.

At present, Gravenhurst is supplied at both 4.16kV in the core area and 12.47kV in the outer areas. Provincial transmission is distant and bulk supply to Gravenhurst is and will be by means of 44kV sub-transmission. This fact commits Veridian to a system dependent on substations in the Gravenhurst area. Veridian has two substations (First Street and Bay) with 44kV to 4.16kV transformers, but load there has grown to the point where a failure at one 4.16kV station cannot be compensated by the remaining 4.16kV station. The current contingency is the replacement of a failed transformer with a system spare transformer already located in Gravenhurst.

The 12.47kV portion of the Gravenhurst system is supplied both from the Hydro One 12.47kV system and from Veridian's James Street 44kV to 12.47kV substation.

Veridian's long term plan is to replace aging 4.16kV assets by converting in the first instance to 12.47kV, and ultimately to 27.6kV as load in the area grows.

Project Description

The 2013-2014 portion of this initiative involves rebuilding an existing feeder line between the 12.47kV James Street substation to the 4.16kV First Street substation. This is an integrated project that will span two calendar years, and involve the replacement of approximately 50 poles and associated equipment at its completion.

The existing feeder carries 44kV supplies to the James substation, and after rebuilding will continue that function. In addition, it will carry a new 12.47kV feeder segment, replacing an existing 4.16kV feeder. The new 12.47kV segment will allow load presently served by the 4.16kV system to be transferred to the 12.47kV system. It is estimated that approximately 0.5MW of load will be transferred from the 4.16kV system to the James substation 12.47kV system. In turn, when combined with future voltage conversion projects, that load transfer will reduce the demand on the existing 4.16kV system to the point that in the event of the failure of one of the 4.16kV substations, the remaining station would be capable of picking up the extra load.

Figure 1 below depicts the locations of the substations and the subject feeder line.

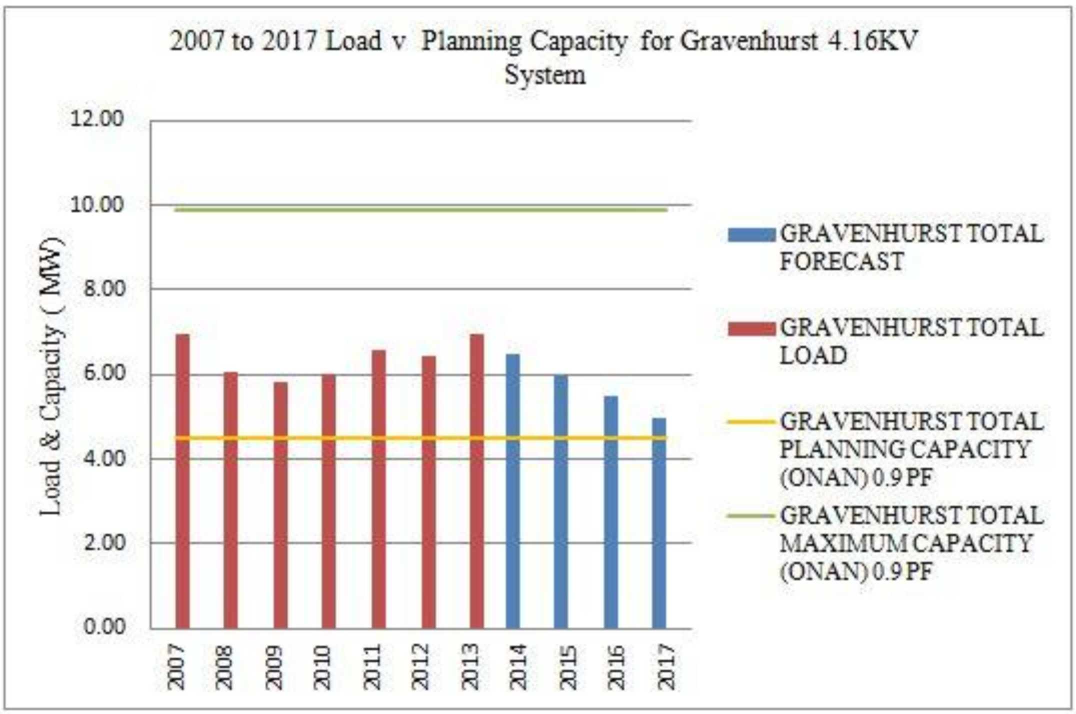
Figure 1: Gravenhurst Voltage Conversion Project

The eventual rebuilding of the First Street substation to include a 44kV to 12.47kV transformer will give Veridian the ability to back up the 12.47kV system in the event of a failure at either the James Street or First Street substations. In addition, it will permit Veridian to transfer 12.47kV load presently served from the Hydro One system with Veridian as an embedded distributor. Converting away from an embedded distributor supply to supply by the Veridian system in the future would reduce Low Voltage charges for Veridian customers.

Evaluation Criteria

The main driver for this project is to relieve a potential overload under first contingency on the 4.16kV system in Gravenhurst. At present, a failure of either the First Street or Bay substations would overload the remaining 4.16kV substation, thus requiring rotating load shedding for an extended period until the fault could be repaired or equipment replaced. This relief will be achieved by transferring load presently supplied by the 4.16kV system to an expanded 12.47kV system. Figure 2 depicts historical and forecast load versus first contingency capacity on the 4.16kV system.

Figure 2: Load versus Capacity on the 4.16kV System



In the longer term, gradual conversion of supplies in the core of Gravenhurst to a new 12.47kV system will permit the retirement of 4.16kV assets which are aged and approaching end-of-life. It will also permit Veridian to serve new load in the core area of Gravenhurst and reduce the relatively higher losses which are intrinsic to lower voltage distribution systems.

The immediate-term transfer of load is a priority for Veridian due to the significant risk of extended outages on the 4.16kV system. The longer term voltage conversion is a medium priority for Veridian, subject to escalation in the case that significant new loads appear on the 4.16kV system or that system begins to deteriorate more rapidly.

Veridian examined the alternative of simply rebuilding the 4.16kV system but rejected that option due to the limited load-serving capability of low voltage distribution systems together with their high rates of loss.

At the same time, the immediate conversion to a 27.6kV system would introduce a third voltage level to the system that is unneeded presently from a load serving perspective. Furthermore, that conversion would require a large, lumpy investment to convert enough load to enable redundancy between substations for purposes of back up and reliability.

The conversion to an existing voltage level at the present time is conducive to interoperability with existing equipment and gradual reinvestment in the distribution system so as to minimize sharp rate impacts.

This project is not expected to have material effects on existing levels of safety, cyber-security, privacy, or regional coordination.

In addition to the economic stimulus provided by the investments in this project, the provision of reinforced electricity infrastructure with lessened risks to reliability is conducive to economic development.

Veridian anticipates that the distribution line losses for the load currently served by the 4.16kV system will be reduced by approximately 1% upon completion of the full conversion from the 4.16kV system to 12.47kV (mid-term) and a further 1% upon conversion to 27.6kV (long term). In turn, this is expected to have a positive environmental impact due to the reduced need to generate electricity.

Category-Specific Requirements: System Service Project

The principal benefits of this project will be enhanced reliability and security of supply, together with improved ability to connect new load and reduced losses.

Veridian anticipates only a very minor impact on regional electricity infrastructure requirements arising from this project, through the off-loading of Veridian's embedded load on local Hydro One feeders. The voltage conversion in Gravenhurst will be coordinated with Hydro One. This project does not embody advanced technology but does target the gradual removal of obsolete technology.

As noted above, the immediate-term transfer of load from the 4.16kV system is a priority to avoid the risk of extended outages. Veridian has planned this undertaking for several years but did not complete it as the previously anticipated load growth did not appear. Further discussion regarding this historical project can be found in the section concerning Gross Asset Variance Analysis Exhibit 2, Tab 1, Schedule 2.

Also as noted above, Veridian assessed technically feasible alternatives to this projects which were rejected for the reasons noted there. Veridian also determined that doing nothing to address the potential first contingency overload is not a viable option due to the severe consequences of such a failure.

Project Cost Summary:	**$0.882 million gross**
Labour & Fleet	$0.450 million
Material	$0.350 million
Contractor/Other	$0.082 million

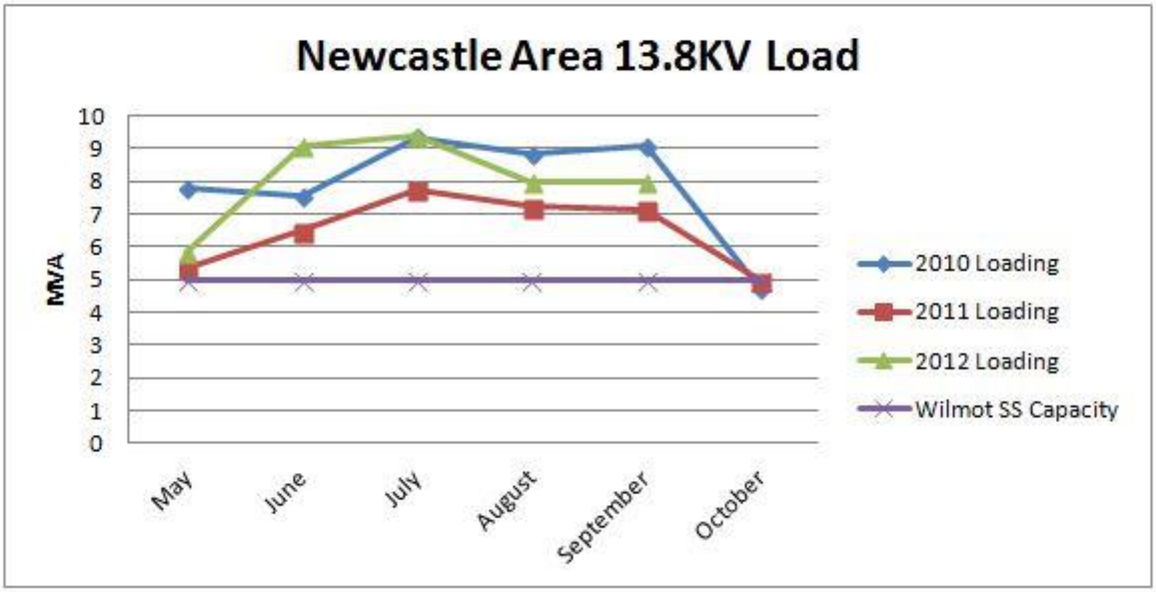
Name of Project	Wilmot Substation Upgrade
Project Classification	System Service
Start Date	September 2013
In Service Date	December 2013
Capital Expenditure	$1.9 million gross

Overview

The Wilmot Substation Upgrade project is proposed primarily to meet system service capacity objectives but also to renew critical equipment that has reached end of life. Under this project Veridian will completely rebuild the substation to add capacity that has become required due to load growth and simultaneously renew equipment.

The Wilmot Substation, together with the Toronto Substation, provides service to the Town of Newcastle. These substations transform 44kV supply to 13.8kV for distribution. The natural, non-forced cooling capacities of the substations are 5MVA and 10MVA, respectively. As load has grown in this area, the ability of the existing infrastructure to meet load under Veridian's standard planning framework has declined, and recent equipment failures at Wilmot have heightened concerns that in the event of a failure at the Toronto Substation, Wilmot could not carry the load that would need to be transferred. In that case approximately 4 MVA of load in the area would be lost for an extended period of up to 24 hours. Summer month peak loading, driven primarily by air conditioning demand, is illustrated in Figure 1.

Figure 1: Newcastle Area Summer Load



Apart from the capacity shortfalls, the switchgear and circuit breakers at Wilmot need to be replaced in any case. This equipment was installed in 1986 and has reached end of life. The switchgear experienced two failures in 2010 and another in 2011, with two of the failures resulting in customer outages. Breaker failures occurred in 2012 and 2013, and in the 2011 case one breaker did not operate properly during a fault. Improper breaker operation during a fault can create severe risks of personal injury and substantial equipment damage.

Due to the nature of the equipment involved, there were limited options available to Veridian to address both the equipment deterioration and the capacity shortfalls. There is no 27.6kV capacity available to permit supplying the load at 27.6kV.

Project Description

This project involves the installation of:

- an engineered ground grid to provide adequate equipment grounding;
- a Sorbweb oil containment system to mitigate environmental risks in the event of a transformer oil leak;
- a new 10/12/16 MVA transformer with on-load tap changing capability to provide needed additional capacity and voltage control capability, with the existing transformer being recovered and used as a system spare;
- a 44kV Transruptor for transformer protection;
- new padmounted reclosers for the 2 feeders emanating from the station, to replace the existing circuit breakers and switchgear, which will be scrapped;
- new feeder protection relaying, to replace the existing relays , which will be recovered and used as spares;
- new copper feeder cables for incoming 44kV supply to the switchgear, cabling from the transformer to the reclosers, and two 13.8kV circuits to the street, totaling 850 metres; and
- an enclosing masonry wall for station security and noise abatement.

This combination of elements is consistent with Veridian's standard for substations in urban locations which must meet electrical standards as well as environmental and community integration requirements. The costs for the individual elements are provided below.

This project is being undertaken during the shoulder load season to ensure that the Toronto substation can carry the load temporarily transferred from Wilmot.

Item	$(millions)	Labour & Fleet	Material	Contractor
Transformer	$0.900	$0.150	$0.600	$0.150
Reclosers(2)	$0.080	$0.010	$0.060	$0.010
Oil Containment	$0.080	$0.000	$0.030	$0.050
Feeder Cables	$0.400	$0.010	$0.350	$0.040
Feeder Duct Banks	$0.160	$0.010	$0.050	$0.100
Masonry Wall	$0.080	$0.000	$0.000	$0.080
44KV Transrupter	$0.100	$0.005	$0.095	$0.000
Relays	$0.050	$0.010	$0.040	$0.000
SCADA	$0.050	$0.005	$0.045	$0.000
Total	**$1.900**	**$0.200**	**$1.270**	**$0.430**

Project Cost Summary:	**$1.9 million gross**
Labour & Fleet	$0.200 million
Material	$1.270 million
Contractor/Other	$0.430 million

Name of Project	13.8kV Loop Feed, Port of Newcastle
Project Classification	System Service
Start Date	August 2014
In Service Date	October 2014
Capital Expenditure	$0.444 million gross

General Information

This system service project is to install a second 13.8kV feeder to provide a loop supply to a major subdivision in the Port of Newcastle area. At present, the 600 customers in the subdivision are supplied through a single radial 13.8kV feeder emanating from the Toronto 44kV to 13.8kV substation. In the event of a failure of that supply path, all customers in the subdivision would be without power until the fault was resolved, which could entail a lengthy outage.

This subdivision has been under construction for the last five years and is now complete, such that the planned loop supply to the area can be completed.

Project Description

This project involves the construction of a 13.8kV feeder carried for 1.9 kilometers on poles owned and to be reconstructed by Hydro One, and for 0.8 km in existing underground ducts owned by Veridian. The overhead pole line segment consists of 32 poles, and presently carries a 44kV circuit on 20 poles with a 27.6kV circuit on 12 poles. Theses 32 poles would be rebuilt by Hydro One to accommodate an additional 13.8kV circuit to be installed by Veridian. Costs for Hydro One to complete this work are estimated and included in the Overhead Line costs in the table below. This type of work is covered by a Joint Use Agreement between Veridian and Hydro One.

Veridian would complete the underground portion of the work by installing underground feeder cable in existing ducts within the subdivision.

Item	$(million)
Overhead Line Costs	0.280
Underground Costs	0.164
Total	0.444

Evaluation Criteria

The trigger for this project is the need to provide a backup or loop supply to a major subdivision of 600 customers which is presently served by a single radial supply. In the absence of a backup supply, a fault in the trunk portion of the feeder or any upstream equipment forming part of the single feeder's supply path would expose those customers to a potentially lengthy outage while the fault was corrected.

This project is a high priority for Veridian given the potentially severe consequences of a fault on a supply path with no backup.

The customers affected by this project will benefit substantially by a significantly reduced risk of lengthy outages, and will be brought to a standard level of supply security typical for Veridian's urban customers. It is unusual for Veridian to be unable to provide an alternate supply for a large number of customers in the event of an equipment failure on its own system. In most similar circumstances supply is maintained automatically in a networked system or Veridian is able to perform switching to quickly restore power to all but a small local area in the immediate vicinity of the fault.

This project will not have a material effect on existing levels of safety, cyber-security, privacy, interoperability or coordination. Apart from the substantially reduced risk of outages, this project is not expected to have significant economic development or environmental benefits.

Category-Specific Information: System Service Projects

As noted above, the principal customer benefit of this project is a substantially reduced risk of lengthy outages.

This project does not have material effects on regional infrastructure requirements and does not embody notable advanced technology beyond that normally associated with a remotely controlled electricity distribution system.

The timing of this project is driven by the construction completion of the affected subdivision. Veridian had intended to complete this work previously, but delayed it due to capital spending constraints resulting from high levels of customer driven, non-discretionary projects.

For the underground portion of this project, there is no reasonable alternative to installing the additional feeder in ducts already existing for that purpose (see above re: u/.g). For the overhead portion of this project, Veridian determined that carrying its feeder on the existing (but rebuilt) Hydro One pole line represented the most economical way of bringing a second feeder to the vicinity of the subdivision.

Project Cost Summary:	**$0.444 million gross**
Labour & Fleet	$0.250 million
Materials	$0.167 million
Contractor/Other	$0.027 million

Name of Project	Oil Containment
Project Classification	System Service
Start Date	May 2014
In Service Date	October 2014
Capital Expenditure	$0.300 million gross

General Information

Under this system service project, Veridian plans to add a passive oil containment system to three of its substations in 2014. This is a continuation of work documented in Veridian's 2010 COS application for 2009 and 2010. As explained in that evidence, Veridian operates a number of substations that pose a risk of significant environmental contamination and associated cleanup costs were there to be a catastrophic transformer failure resulting in the release of large quantities of transformer oil into the environment. Both the risk of release and the consequences of release vary among substations, and Veridian's approach has been and is proposed to be to implement a passive, no-maintenance oil containment system at the sites where the combined risks and consequences are highest. The presence of nearby watercourses is one factor that heightens the consequences of a contaminant release.

Given the completion of high risk stations in 2009 and 2010 combined with heavy engineering workload and competition for capital dollars from non-discretionary projects, no oil containment projects were completed between 2011 and 2013. However, Veridian plans to complete additional stations in 2014 and future years. At the completion of the planned work, Veridian will have addressed the top 20 stations identified in the risk analysis.

Project Description

Veridian plans to install the oil containment systems at the Sunderland 44kV to 8.32kV substation and two Belleville stations; Sidney 44kV to 13.8kV and Herchimer 44kV to 4.16kV. Veridian intends to use the same technical approach as in earlier projects and place a contractor-installed membrane below ground level that blocks transit of oil through it, while allowing ground and melt water to travel unimpeded.

Evaluation Criteria

The trigger for these projects is the need to substantially reduce the risk of an uncontrolled release of transformer oil into sensitive environmental areas in the event of a catastrophic transformer failure.

The installations planned for 2014 are high priority projects for Veridian. Sunderland substation supplies the village of Sunderland. It has the highest priority ranking among the substations remaining to be equipped with oil containment. It is adjacent to wetlands connected to the Beaver River and the pumping station supplying drinking water to Sunderland. The second and third substations planned for 2014 are the Sidney and Herchimer substations in Belleville. These are located nearby municipal drainage within residential areas.

The Sunderland substation has only one 5MVA transformer supplying the village. This location will require additional detailed engineering to plan and execute the work to modify the existing station in order to accept a temporary power supply for the village while the oil containment system is installed. Due to the single point of supply for the village, there are no other planned outages of a sufficient duration to incorporate the oil containment installation. Additionally, no additional substations in the area are planned due to negligible load growth in that district. The estimated cost to complete the oil containment along with the necessary station modifications and temporary power arrangements at this substation is $0.15 million. The loads at the Belleville substations can be temporarily resupplied from other substations in Belleville. Costs per station for Sidney and Herchimer are estimated at $0.075M.

This project is not expected to have material effects on existing levels of safety, cyber-security, privacy, coordination, interoperability, or economic development.

This project will produce a significant environmental benefit through the substantial reduction of a material risk to the environment.

Category-Specific Information: System Service Projects

Veridian strives to operate its distribution system at reasonable cost with high regard for environmental protection. In practice this means that Veridian seeks to mitigate unusual environmental risks arising from its operations using cost effective approaches on a prioritized basis. This project contributes to the achievement of those goals and will substantially mitigate the risk of environmental contamination and the potential disruption of drinking water supplies.

Veridian must also meet other obligations as a distributor and must operate within a finite budget, which means that Veridian cannot undertake to install oil containment systems at all locations where they are needed in 2014. However, Veridian believes that doing nothing to mitigate identified risks in this area cannot be justified, and that a prioritized approach where the highest risks are mitigated first is appropriate.

Project Cost Summary:	**$0.300 million gross**
Labour & Fleet	$0.050 million
Materials	$0.100 million
Contractor/Other	$0.150 million

Material Investments - 2013 and 2014 - General Plant Category - Fleet

Name of Project	Bucket Truck Replacement
Project Classification	General Plant - Fleet
Start Date	January 2014
In Service Date	December 2014
Capital Expenditure	$0.4 million

Description of the Project

The project consists of the purchase of a double bucket truck with a 55 foot working height to replace similarly equipped Veridian fleet vehicle V485.

Vehicle V485 is regularly used and its age substantially exceeds Veridian's 10 year threshold for replacement or refurbishment consideration. It will be 17 years old in 2014.

The option of refurbishing vehicle V485 was considered and rejected due to its advanced age, the existence of extensive rust and corrosion on the vehicle chassis and body, and the need for an engine overhaul, transmission repairs, and new tires.

Benefits of the Project

The new replacement vehicle will initially be used to support ongoing lines construction and maintenance activities in Belleville. It will provide for reduced maintenance costs, increased reliability, and enhanced worker safety.

Project Cost Summary:	$0.4 million
Labour & Fleet	$0

Materials	$0.4 million
Other	$0

Material Investments - 2013 and 2014 - General Plant Category - Information Technologies

Name of Project	GIS Enhancements
Project Classification	General Plant – Information Technology
Start Date	January 2013
In Service Date	December 2013 - $0.140 million – Annual Investment December 2014 - $0.150 million – Annual Investment
Capital Expenditure	$0.290 million gross

Refer to Historical Project Descriptions found in Exhibit 2, Tab 2, Schedule 2 of this Rate Application.

Project Cost Summary:	**$0.290 million gross**
Labour & Fleet	$0.160 million
Material	$0.099 million
Contractor/Other	$0.031 million

Name of Project	High Availability (HA) Business Continuity Data Site
Project Classification	General Plant – Information Technology
Start Date	January 2013
In Service Date	December 2013
Capital Expenditure	$0.350 million gross

Overview

The development of an offsite HA site is to ensure that Veridian's centralized computer systems will continue to operate seamlessly should there be a system component/network outage at the primary server location at the company's Ajax head office.

The project includes the purchase of a commercial office unit that will house the HA site, as well as improvements to the office unit such as new Heating, Ventilation and Air Conditioning ("HVAC") capacity, backup generation, fibre connectivity and computer racking.

A summary of the capital costs is as follows:

Item	**($000's)**	**Completion Status**
Building	160	Completed
HVAC	30	October 2013
Generator	30	November 2013
Electrical	50	October 2013

Item	($000's)	Completion Status
Security	10	October 2013
Fibre	50	October 2013
Moving Costs	5	November 2013
Roofing	10	October 2013
Internal Labour	5	December 2013
Total	**$350**	

Project Description

In 2009 Veridian invested in a virtualized server environment. This has allowed for a substantial reduction in the number of servers, reduced operating costs and improved operating efficiencies. Specific benefits centre around a reduction in server provisioning time. The time to complete upgrades and perform maintenance is reduced, change management is more efficient, energy costs are reduced, applications can be released faster and testing time can be reduced.

In a virtual setup there are two separate environments that house the applications and data that mirror one another. Should one environment fail the other will take over. This allows work to continue as normal and provides both customers and staff with a stable environment where downtime due to component failure and network outages/interruptions is minimized.

Since implementation, both of the mirrored environments have been housed in the same location.

While working with a consultant in the development of Veridian's Business Continuity Disaster Recovery Plan, it was decided that in order to minimize risk the two environments should be physically separated and one should be placed in what is referred to as a High Availability (HA) site. The HA site is an important component of Veridian's business continuity/disaster recovery initiative.

The business continuity/disaster recovery plan also calls for Veridian's Clarington office to act as business continuity site for key operational and customer service staff in the event of a disaster. Connectivity between Veridian's main Ajax location, the business continuity site and the HA site would be put in place. This Clarington site is planned for 2014 and further information is provided at Exhibit 4, Tab 2, Schedule 2.

This HA site will also provide redundant locations for systems key to customer support and reliability such as Veridian's SCADA, GIS and phone/customer contact/IVR system.

Customer service levels for both administrative services such as Veridian's Customer Contact Centre and system reliability will be enhanced. Customers should experience minimal service interruptions created by network or application/system issues. Failures will be instantaneously transferred to the mirrored site.

Project Analysis and Solutions Considered

Various options for locating the HA site were considered. They included:

1. locating the HA site within a substation,
2. locating in a separate structure on the property where the virtual server currently exists and
3. purchasing a site to locate the equipment.

Options 1 and 2 were eliminated due to zoning, proximity, and space issues.

Veridian is continually in the process of reviewing and "hardening" the configuration of its system and network to ensure cyber security and privacy requirements are met. Veridian's standards for network security have been applied within the design and configuration of the HA site.

Project Cost Summary:	**$0.350 million gross**
Internal Labour & Fleet	$.005 million
Building	$.160 million
Communication Infrastructure	$.050 million
Facilities Upgrades	$.135 million

Name of Project	Mobile Computing
Project Classification	General Plant – Information Technology
Start Date	January 2013
In Service Date	December 2013 - $0.400 million – Phase 1 December 2014 - $0.300 million – Phase 2
Capital Expenditure	$0.700 million gross total

Refer to Historical Project Descriptions found in Exhibit 2, Tab 2, Schedule 2 of this Rate Application.

Project Cost Summary:	**$0.700 million gross**
Labour & Fleet	$0.084M
Material	$0.616M
Contractor/Other	$0

Name of Project	Unified Messaging – Phone System Replacement-Phases 1 and 2
Project Classification	General Plant-Information Technology
Start Date	January 2013
In Service Date	November 2013- $0.451 million-Phase 1 (Ajax location) June 2014 - $0.060 million-Phase 2(Clarington, Belleville and Gravenhurst locations)
Capital Expenditure	$0.511 million gross total

Description of the Project:

This project is a multi-phase replacement of Veridian's telephone system and call centre management software over the bridge and test year. The majority of the expenditure for the main system, which will be located at Veridian's Ajax service centre, will occur in 2013. Veridian's district offices will be connected to the main system through modular, low cost investments in the test year.

The project requires a capital investment of $0.511 million over the bridge and test years and ongoing incremental operating costs of approximately $0.041 million for hardware and software licensing, system monitoring and technical support costs.

Veridian's call centre management software was approximately thirteen years old and many of the major components had reached end of life and were no longer supported by the vendors. This situation, left unresolved, presented a significant risk to Veridian's ability to provide the expected level of service to its customers.

Solutions Considered/ Evaluation Criteria

Three of the leading vendors operating in the mid-size phone system markets were asked to provide solution proposals. A scoring matrix was developed which focused on the merits of vendor knowledge and support, technical infrastructure, key system features, pricing over the entire system lifecycle and others such as ability to customize, scalability and the ability for internal support of the system.

Benefits of the Project:

The new software has many enhanced features such as staff scheduling, improved reporting, agent call scoring and control centre messaging. It will also provide redundancy for disaster recovery and ensure regulatory compliance requirements are more easily met.

The new platform also allows for Veridian's multiple service centres to be connected through one communication system.

A pilot to test the viability of customer service agents working from home can also be accomplished with the new software.

Project Analysis and Project Alternatives

The investment was considered against other major capital projects and was deemed to be high priority due to the end of life conditions. This is a critical asset as it supports front line communications between Veridian and its customers.

As the end of life condition of the equipment necessitated replacement of the system, the project analysis focused on the solutions provided by various vendors. A review of the capital and operating costs over the expected life of the equipment was completed. A standardized scoring matrix was also developed and used to evaluate the various alternatives. The matrix took into consideration both quantitative factors such as total cost and qualitative factors such as quality of support and complexity of the solution in determining the choice of vendor.

Project Cost Summary:	**$0.511 million**
Internal Labour	$0.038 million
Hardware	$0.118 million
Software	$0.250 million
Implementation – Contractor	$0.105 million

Name of Project	Business Continuity/Disaster Recovery Site
Project Classification	General Plant-Information Technology
Start Date	May 2014
In Service Date	October 2014
Capital Expenditure	$0.200 million gross

Overview

The project primarily entails investment in computer hardware, software and communication infrastructure to develop a business continuity/disaster recovery site. This will allow for continued operations of critical services in the event of circumstances that disrupt the ability to carry on business at Veridian's primary Ajax location. The project requires a capital investment of $0.200 million and ongoing incremental operating costs of $0.085 million annually. Further information at the associated operating costs are provided at Exhibit 4, Tab 2, Schedule 2.

Description of the Project

Should a disaster occur that renders Veridian's primary location as inoperable the ability to conduct even basic business activities would be limited.

In 2013, Veridian invested in a "High Availability" (HA) site, which protects against component failure and network work related issues and provides instantaneous continuity for customers and operations to systems and applications used in conducting business activities. This project is described at Exhibit 4, Tab 2, Schedule 2.

The disaster recovery site will be a separate, physical location where a limited number of staff can go to maintain the operations of the LDC should the primary location become inoperable.

Primary operations that would be conducted at the disaster recovery site would be the operation of the 24/7 control centre and the customer call centre.

The existing communication infrastructure at the Clarington location is sufficient to meet the existing use as an operations service centre and temporary office workspace for employees when carrying out business activities in the Clarington area but is not sufficiently robust to serve as a standalone facility for business continuity purposes. The BC/DR site requires a technology/communication platform sufficient in size and capability to accommodate 28 essential personnel engaged in control room and call centre activities. The $0.200M investment relates to desktop network equipment ($0.0545M), a fibre build to the communication providers point of presence ($0.100M) and contractor and internal labour ($0.045M).

The business continuity/disaster recovery location will be located approximately 35 kilometers away from the primary location and the HA site but will be linked to the primary location and the HA site for redundancy purposes. The business continuity site has to be close enough to the primary location that staff can easily be relocated but far enough from the primary location that it does not fall within the same zone of influence.

Solutions Considered

Several options were looked at for the location of the disaster recovery site. Veridian's Clarington office was chosen as it far enough away from the primary location and the facility was already owned by Veridian which limited costs.

Evaluation Criteria

The key drivers for the project were customer value, efficiency and reliability.

In the event of a catastrophic situation a command centre is required to keep customers informed and where operations can continue with minimal disruption or reconfiguration to lead the restoration of the distribution network and minimize service interruptions.

The BC/DR plan was developed in conjunction with a consultant who specializes in this area. During the development of the plan it was identified that in order to reduce risk and improve customer service a dedicated site should be developed where services to customers could be maintained should a disaster occur.

The investment was considered against other major capital projects and was deemed to be high priority. It was deemed that the potential risk for long delays in operations and power restoration activities needed to be minimized.

In the event of a catastrophic occurrence having a functional disaster recovery site will improve safety for both customers and staff. Customers will continue to have the ability to contact Veridian staff to report hazardous situations and to receive updates on power restoration.

Veridian is continually in the process of reviewing and "hardening" the configuration of its system and network to ensure cyber security and privacy requirements are met. Veridian's standards for network security have been applied within the design and configuration of the HA site.

Project Cost Summary:	**$0.200 million**
Internal Labour	$0.045 million
Purchases	Equipment : $0.055 million Communication Infrastructure: $0.100 million